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Submitted via www.regulations.gov

June 23, 2023

The Honorable Michael S. Regan
Administrator
The U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

**RE:** Comments of the American Public Power Association on the National Emission Standards for Hazardous Air Pollutants: Coal-and-Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review; Proposed Rule, 88 Fed. Reg. 24854 (April 24, 2023) Docket ID No. EPA–HQ–OAR–2018–0794.

Dear Administrator Regan:

The American Public Power Association (APPA or Association) appreciates the opportunity to submit the attached comments in response to the U.S. Environmental Protection Agency's (EPA or Agency) proposed "National Emission Standards for Hazardous Air Pollutants: Coal-and-Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review."[1]

APPA is the national service organization representing the interests of more than 2,000 not-for-profit community and state-owned electric utilities that together provide electricity to approximately 49 million Americans and employ approximately 96,000 people. Most public power utilities have 10 or fewer employees and serve towns, villages, or counties with fewer than 10,000 people, and all but 144 of the nation's public power utilities would be considered a "small governmental jurisdiction" under the Regulatory Flexibility Act.[2]

APPA has concerns as to the legal basis and technical underpinnings of the Proposed Rule. As further discussed in the enclosed comments, APPA has concerns with the agency's analysis of the filterable particulate matter and mercury baselines, on which the proposed limits are founded, the removal of compliance measure flexibilities, and the assumptions in EPA's regulatory impact analysis. We believe EPA's decision to affirm the robust and technically sound residual risk analysis concluded in 2020 is well supported. We also support EPA's analysis to retain the current mercury standard for bituminous coal units and non-lignite units. The acid gas and organic hazardous air pollutant work practice standard should also be affirmed, as proposed.

[1] 88 Fed. Reg. 24854 (April 24, 2023) (Proposed Rule).
[2] 5 U.S.C. §§ 601-12.

APPA looks forward to working with the agency as it considers APPA's recommendations and technical reports that accompany these comments. If you have any questions regarding APPA's comments, please contact Ms. Carolyn Slaughter via email at CSlaughter@PublicPower.org or call (202) 467-2900.

Sincerely,

Carolyn Slaughter

Carolyn Slaughter
Senior Director, Environmental Policy
American Public Power Association

# COMMENTS OF THE AMERICAN PUBLIC POWER ASSOCIATION ON THE NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: COAL- AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS REVIEW OF THE RESIDUAL RISK AND TECHNOLOGY REVIEW; PROPOSED RULE

88 Fed. Reg. 24854 (April 24, 2023)
Docket ID No. EPA–HQ–OAR–2018–0794


Submitted by:
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## I. Introduction

The American Public Power Association (APPA or the Association) appreciates the opportunity to provide comments on the Environmental Protection Agency's (EPA or Agency) proposed rule entitled, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review" (the Proposed Rule).[1] This Proposed Rule concerns the Mercury and Air Toxics Standards (the MATS Rule) under Clean Air Act (CAA) Section 112. Our members operate power generation plants that currently comply with the MATS Rule and will be directly affected by revisions to the MATS Rule. Therefore, the Association and its members have a strong interest in commenting on the proposed revisions in this rulemaking.

APPA is a trade association composed of not-for-profit, community-owned utilities that provide electricity to 2,000 towns and cities nationwide. APPA protects the interests of the more than 49 million people that public power utilities serve and the 93,000 people they employ. Our association advocates and advises on electricity policy, technology, trends, training, and operations. Our members strengthen their communities by providing superior service, engaging citizens, and instilling pride in community-owned power.

Public power utilities continue to be dedicated to clean air in our communities and the protection of the environment. Our members have made significant investments to reduce emissions and become compliant with the suite of air regulations that EPA has promulgated over the last ten years. Many members continue to pay for those environmental compliance investments through loan obligations. For these reasons, APPA members have a significant stake in the revisions proposed in this rulemaking, which will have a significant financial impact on our members.

APPA appreciates EPA's recognition and consideration of the impacts of the Proposed Rule on public power as small entities and on grid reliability as a whole. Thank you for your consideration of our specific comments on the Proposed Rule described below.

## II. Executive Summary.

Our nation's air quality has dramatically improved since 1990, according to a recently released EPA clean air report.[2] Nationally, all major air pollutants have fallen, including hazardous air pollutants (HAPs), which is the topic of this rulemaking. In fact, EPA reports this progress despite increases in air concentrations of pollutants associated with wildfires.

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[1] 88 Fed. Reg. 24854 (Apr. 24, 2023).
[2] Our Nation's Air, June 2023, https://gispub.epa.gov/air/trendsreport/2023/documentation/AirTrends_Flyer.pdf

At the same time, our nation is facing an energy reliability crisis. The North American Electric Reliability Corporation (NERC) recognizes the unprecedented, rapid evolution of the electricity grid due to the retirements of fossil generation and renewable generation coming on-line. A recent study projects that some areas of the country have inadequate electricity supply resources even under normal weather conditions, while many areas are at high risk during severe weather events.[3] NERC cautions:

> Regulatory and policy-setting organizations should use their full suite of tools to manage the pace of retirements and ensure replacement infrastructure can be timely developed and placed in service.[4]

Despite this warning, EPA proceeded with releasing an unparalleled suite of environmental regulations impacting the power sector. Heedless of major air quality strides, these rulemakings propose costly emissions reductions that EPA projects to cause further fossil fuel retirements. The Proposed Rule is part of EPA's portfolio, directly affecting fossil generation assets that power America's cities and municipalities. Public power entities require time and resources to pivot to EPA's environmental policy agenda, while maintaining safe, affordable, and reliable power.

EPA released this Proposed Rule at a time when fossil fuel-fired electric generating units (EGUs) are contending with significant rulemakings that will create a sizeable cumulative cost burden on the industry in a short time period, most by 2028. For example, in addition to the Proposed Rule, there are currently open comment periods on other complex proposed rules directly affecting public power:

- Proposed Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments, and
- 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 that ends on August 8.

In addition, EPA published the final Good Neighbor Federal Implementation Plan (FIP) on June 5, 2023, which proposes costly controls for EGUs in affected upwind states. EPA's public comment period recently ended for the Supplemental Effluent Limitations Guidelines and Standards (ELGs) that proposes costly wastewater technologies. The regional haze program is in the midst of the second planning period that ends in 2028. Many states recently submitted or are in the process of finalizing their state implementation plans (SIPs) which involve emissions reductions to fulfill state reasonable progress goals.

[3] NERC, Long-Term Reliability Assessment, December 2022 at 5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf
[4] *Id.* at 13.

The costs of this Proposed Rule should be considered as required by CAA Section 112. It is crucial for EPA to evaluate the overall regulatory context. The burden of environmental compliance on municipalities and other public power entities and their customers is cumulatively affected by the compliance timelines of these concurrent rulemakings. Entities with limited resources require time to triage environmental compliance costs.

EPA's suite of new rules place reliability at risk. In March of 2023, Department of Energy (DOE) Secretary Granholm and EPA Administrator Regan signed a Memorandum of Understanding on electric sector resource adequacy and reliability coordination. Their shared objective of supporting the continued delivery of "a high standard of reliable electric service" is jeopardized by the numerous other rules that will affect crucial baseload fossil power plants. This Proposed Rule has a meaningful role among these rules, as it proposes costly retrofits and other requirements that are drivers for fossil plant retirements. The collective significant impact on reliability that the suite of regulations will have on dispatchable generation must be evaluated by EPA, DOE, regional transmission organizations (RTOs), affected EGUs, and others.

EPA's proposal to lower the particulate matter (PM) 2.5 annual standard further complicates the reliability equation. Presently, EPA is considering public comments in response to its proposed rule to reconsideration of the National Ambient Air Quality Standards for Particulate Matter. If EPA lowers the PM 2.5 annual standard, EGUs would be restricted from pursuing options for siting new electricity generation, particularly in urban areas that have a higher background PM 2.5 value due to anthropogenic sources. That final rulemaking is scheduled for release later this year.

APPA has concerns as to the legal basis and technical underpinnings of the Proposed Rule. EPA uses the MATS RTR process to justify substantial changes to the MATS Rule, far beyond what Congress directed in Section 112(d)(6). To technically justify these changes, EPA made choices to skew the filterable particulate matter (fPM) and mercury (Hg) baselines, which the proposed lower limits hinge. Next, EPA went beyond the health and technology reviews requirements by proposing to reduce the MATS Rule's compliance measure flexibilities and created technical challenges with proposed changes to monitoring provisions. Some of the proposed requirements will even *increase* fossil fuel emissions. Finally, EPA makes unrealistic assumptions in the Proposed Rule's regulatory impact analysis that the Inflation Reduction Act (IRA) of 2022 will fuel a dramatic energy transition in only seven years.

APPA applauds EPA's decision to affirm the robust and technically sound residual risk analysis concluded in 2020. Although the technology review is a separate analysis, CAA Section 112(d)(6) statutory considerations, such as cost, must be viewed in the context of the lack of an unacceptable health risk or adverse environmental effects posed by the covered EGUs. EPA's benefit-cost analysis for this regulatory proposal does not factor in any air toxics-related avoided health impacts as benefits of the proposed regulatory changes. APPA urges EPA to place more weight on the cost impacts, reliability considerations, and practical challenges this Proposed Rule presents. We note that the current MATS Rule protects overburdened communities from unacceptable health or environmental effects.

APPA requests consideration of the following specific technical recommendations:

- Correct the flawed fPM baseline to accurately account for current EGU emissions and fPM control device capabilities.
- Recognize that EGUs vary in different seasonal and operational conditions as well as on a unit-by-unit basis due to size, unit type, fuel, and climate. A compliance margin is necessary to account for these differences.
- Correct the fPM cost analysis to quantify the appropriate number of fPM upgrades and project costs such that the cost is not underestimated.
- Reconsider and revise the small entity portion of the economic impact analysis to reflect the appropriate cost impacts and all affected entities identified in our comments.
- Consider the time frames in which certain fPM control upgrades and installations can realistically occur, particularly given the financing limitations and requirements of public power entities.
- Retain the option to stack test for fPM and non-metal HAPs and use of PM continuous parametric monitoring system (CPMS).
- Re-evaluate the underestimated one-time and ongoing operational costs to install PM continuous emissions monitoring system (CEMS).
- Reconsider the substantial mercury reductions proposed for lignite-fired units that rely on flawed technical assumptions as to the capabilities of those units.
- Adopt reasonable revisions or keep the current PM CEMS correlation test requirements so as not to overburden public power entities.
- Refrain from overvaluing the impacts of the IRA as the basis for the regulatory impacts analysis for this Proposed Rule.

APPA supports EPA's Section 112(f)(2) residual risk conclusions that confirm the EGUs covered by this proposal pose no unacceptable health risks or adverse environmental effects. We also support EPA's analysis to retain the current mercury standard for bituminous coal units and non-lignite units. The acid gas and organic work practice standard should also be affirmed, as EPA proposes. APPA asks EPA to take the following steps to reconsider and revise its approach in the Proposed Rule:

- Revise the fPM emissions limitation based on a corrected fPM baseline and cost impacts but, in no event, lower the fPM limitation below 0.010 lb/mmBtu.
- Retain the options for performance testing for fPM, with the low emitting EGU (LEE) option, and non-metal HAPs with the LEE option and allow PM CPMS monitors as a compliance measure.
- Remove the minimum sample collection volume of 4 dry standard cubic meter (dscm) of sample per run for PM CEMS.
- Keep Startup Definition 2.

- Revise the proposed mercury emissions limitation for lignite units to a higher attainable standard.

Finally, we request consideration of public power entities as a unique set of generators with special cost sensitivities, human resource limitations, financing, project timing, and reliability characteristics.

## III. EPA's actions under the Proposed Rule exceed the statutory boundaries of CAA Section 112.

### A. Background on Section 112 and this Proposal.

The Proposed Rule takes action under CAA Section 112's health-based residual risk review and technology review process, together known as risk and technology review (RTR). EPA uses the technology review portion of CAA Section 112 to propose lower emissions limitations.

Congress defines EPA's scope of review for the RTR under the CAA. CAA Section 112(d)(6) defines the technology review for air toxics standards such as MATS:

> The Administrator shall review and revise, as necessary (taking into account developments in practices, processes, and control technologies), emission standards promulgated under this section no less often than every 8 years.[5]

CAA Section 112 does not require EPA to recalculate the maximum achievable control technology (MACT) floor from the original standard.[6] The statutory language, "review, and revise as necessary" does not impose that type of analysis.[7] Rather, the review process is more limited and defined by statute as the one-time residual risk review and the octennial technology review. In addition, costs are implied as a component of the RTR analysis.[8]

EPA originally finalized the MATS RTR on May 22, 2020 (the 2020 MATS RTR analysis).[9] In that rulemaking, EPA determined that the residual risks from coal-fired and oil-fired EGUs were acceptable and did not identify any new technologies to control hazardous air pollutants (HAPs) for these units[10]. EPA finalized the RTR without any changes to emissions standards or work practices. This 2023 proposal responds to President Biden's Executive Order 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," for EPA to review the

[5] 42 U.S.C. § 7412(d)(d).
[6] *NRDC v. EPA*, 529 F.3d 1077, 1083 (D.C. 2008) (*NRDC*).
[7] *Id.*
[8] *Association of Battery Recyclers Inc. v. EPA*, 716 F.3d 667, 673 (D.C. Cir. 2013).
[9] 85 Fed. Reg. 31286 (May 22, 2020).
[10] APPA supported the conclusions in final 2020 MATS RTR at the time of proposal. *See* https://www.regulations.gov/comment/EPA-HQ-OAR-2018-0794-1185

2020 MATS RTR and to consider proposing a notice of proposed rulemaking suspending, revising, or rescinding 2020 MATS RTR rule.

**B. Congress did not create the RTR process as an open-ended opportunity to reimagine a MACT standard.**

EPA did not find any developments in control technologies, practices, or processes in 2020 or in 2023. With respect to filterable particulate matter (fPM), the Proposed Rule states that EPA found "no new practices, processes, or control technologies for non-Hg HAP."[11] This finding should have signaled the end of the EPA's statutory inquiry.

Instead, EPA opted to go beyond its statutory directive in 2023 and re-examined changes in emissions data, costs, and monitoring devices. EPA labels these changes as "developments." Yet data changes alone are outside of the statutory technology analysis if they are not tied to practices, processes, or control technology developments in the record. The Proposed Rule does not explain why fPM and mercury data have changed, as further discussed.

The D.C. Circuit determined that EPA could not revise a MACT standard in the RTR process unless "developments" happened after the issuance of the original rule.[12] In *NASF*, EPA identified several pre-existing technologies in its analysis (control devices, HEPA filters, tank hoods, fume suppressants) and discussed improvements in the control performance resulting in emissions reductions. The *NASF* court found this was a sufficient development because EPA discussed the impact of the developments and examined what emissions levels could be achieved. *Id*. The key inquiry was whether the record supports a shift in analysis over time – rather than simply revisiting and revising the original standard without a reason or support.

In this Proposed Rule, EPA's analysis does not uncover what new practices, processes, or control technologies occurred since the development of the MATS Rule in 2012 or since the reconsideration in 2020. Instead, EPA relies on the same control technologies that were considered in 2012 (fPM: electrostatic precipitator (ESP) and baghouse (fabric filter); Hg: combination of sorbent injection and activated carbon injection).[13] EPA did present new fPM data from the Agency's WebFIRE database and collected limited information from lignite units under CAA Section 114 requests. But EPA's analysis does not present information sufficient to show any actual change in practice, other than simply reneging on its conclusions in the original rule. EPA does not offer a reasonable basis for coming to a different conclusion with respect to fPM and mercury emissions from lignite units in only three years since the 2020 Final Rule. The RTR process does not allow EPA to simply revisit a standard and change its mind

[11] Proposed Rule at 24,868.
[12] *National Association for Surface Finishing v. EPA*, 795 F.3d 1, 11 (2015) (*NASF*).
[13] *NASF*, 795 F.3d at 11 ("developments" must happen after the issuance of the original rule).

without sufficient scientific and technical bases. The record must support this shift in outcome.[14]

EPA has recalculated the fPM costs of MATS technologies and monitoring devices. If this analysis is valid, then changes in cost could be supported for applying an existing, previously infeasible technology due to cost. However, this is not the case here. Even assuming *for the sake of argument* that EPA's cost analysis is valid, the fPM technologies applied in this proposal –electrostatic precipitators (ESPs) and baghouse (fabric filter)–are currently-used controls/devices for compliance with the MATS Rule. In other words, since these technologies were not eliminated due to cost in 2012, EPA's cost position has not changed from the original rulemaking. For this rulemaking, costs are not a valid new "development" in accordance with Section 112(d)(6).

While EPA relies on improved fPM and mercury emissions data to support its decisions, better data may be indicative of new practices, processes, or control technologies, but the inquiry does not end there. A reasoned inquiry requires that EPA delve into what these improvements are. In other words, EPA has not identified the root cause of the emissions reductions.

### C. The CAA RTR process is not prejudiced against preserving the status quo.

EPA rejects proposing a fPM limit of 0.015 lb/MMBtu simply because "it would largely leave in place the status quo."[15] EPA appears to confuse its statutory charge. Prior RTR analyses confirm that EPA does not have to make a decision to strengthen an air toxics standard. EPA may affirm the standard, as it did in the 2020 MATS RTR analysis. EPA should eliminate this apparent bias against preserving the status quo. Moreover, EPA provides no rationale as to why 0.015 lb/MMBtu was originally considered to be a low emitting EGU, and now that LEE unit would exceed the proposed fPM limit by 50 percent. This is a perplexing lack of explanation in light of the EPA statement, "our review of the fPM compliance data for coal-fired EGUs indicated no new practices, processes or control technologies for non-Hg metal HAP."[16]

Similarly, EPA justifies its position to set lower fPM limits by stating that this action is consistent with Section 112's direction to achieve the "maximum degree of emissions reductions while taking into account the statutory factors, including cost."[17] EPA confuses the appropriate standard to be used in the RTR review, which is described in CAA Section 112(d)(6) rather than Section 112(d)(2). Oversimplification of Section 112 misstates the appropriate standard and ignores EPA's RTR charge in this rulemaking.

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[14] *NASF*, 795 F.3d at 11-12.
[15] Proposed Rule at 24,871.
[16] *Id.* at 24,868.
[17] *Id.*

### D. The CAA RTR process targets residual risks and control technologies but is not designed to address changes in monitoring methodology and devices that do not impact emissions.

The Proposed Rule goes beyond its statutory mandate by eliminating fPM compliance measures. CAA Section 112's technology review is focused on the control technologies that impact air toxic emissions. The statute does not require a review of compliance measures – which do not have a direct correlation with improved emissions.

The Proposed Rule eliminates fPM compliance by performance (stack) tests in favor of PM CEMS for coal-fired and lignite –fired units. EPA justifies this decision by stating that PM CEMS have the benefits of "increased transparency and accelerated identification of anomalous emissions."[18] EPA's assumption regarding improved air emissions is not supported by the record, as further discussed *infra*.[19]

EPA acknowledges that in the 2012 Portland Cement rulemaking, the agency was aware of the difficulty in using PM CEMS to demonstrate compliance with a fPM emission limit in the range of 5 to 8 milligrams of air pollutant per dry standard cubic meter (mg/dscm).[20] In this proposal, EPA attempts to dismiss comparisons to the Portland Cement rule by asserting that the particle characteristics between the two source categories are different. While the particle characteristics may indeed be different, 5 to 8 mg/dscm is a low PM concentration regardless of the size, shape, or constituency of the particles. In the Portland Cement rule, EPA recognized then that longer run times would not solve the problem created by a very narrow data range for the correlation testing associated with a very low emission limit.[21] The Agency correctly concluded that reference method measurement uncertainty coupled with a limited data range would make establishing a meaningful PM CEMS correlation curve next to impossible.

Section 112 standards do not have to employ continuous emissions monitoring, nor is there a preference for employing them.[22] EPA simply must show reasonable assurance of compliance with the emissions standards.[23] Here, EPA found that the stack test option was sufficient as a compliance measure in 2012 and in 2020. Since 2023, EPA has not put any evidence into the record that demonstrates stack testing is inadequate. In fact, EPA has previously argued that quarterly stack tests are sufficient to assure compliance, and the D.C. Circuit found EPA's explanations reasonable.[24]

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[18] Proposed Rule at 24,857.
[19] We also address the flaws and underestimates in EPA's one-time and annual cost findings for PM CEMS as a compelling reason to pivot away from eliminating stack testing, *infra*.
[20] The Portland Cement fPM emission limit is expressed in the units of pounds of particulate per ton of clinker produced. Thus, the conversion to PM concentration (mg/dscm) is not exact but depends on plant-specific parameters.
[21] 77 Fed. Reg. 42,368, 42374 (July 18, 2012).
[22] *See, e.g.*, *Sierra Club v. EPA*, 353 F.3d 976, 990-91 (D.C. Cir. 2004).
[23] *Id.* at 991 ("There is no presumption in favor of any particular type of monitoring.").
[24] *See White Stallion Energy Ctr v. EPA*, 748 F.3d 1222, 1255 (D.C. 2014) (reversed on other grounds).

In summary, EPA has no statutory basis or factual basis for eliminating stack testing as a compliance measure. The MATS record does not support eliminating this option.

## IV. EPA's decision to affirm the CAA Section 112(f)(2) health-based review is appropriate.

The Proposed Rule affirmed the 2020 Final Rule's determination that there were no unacceptable health risks or adverse environmental effects posed by the covered EGUs. APPA supports EPA's decision to reaffirm the 2020 residual risk review. That 2020 analysis was robust and consistent with past methodology for this analysis. EPA's analyzed exposure risk acceptability, including an ample margin of safety and any adverse environmental effects resulting from HAP emissions from EGUs subject to MATS. Specifically, EPA determined that the current MATS standards are sufficient to protect public health and to prevent an adverse environmental effect.[25] In the reconsideration, EPA reaffirmed this conclusion. No new information was available to impact the prior analysis. We believe this finding is reasoned and should be finalized.

APPA suggests that EPA consider the technology review in light of the favorable finding that EGUs are not creating an unacceptable health risk to health or adverse environmental impacts. While the technology review is a separate component, that review *cannot* be performed in a vacuum. The Proposed Rule requires that certain EGUs undertake substantial fPM and mercury control projects. These costs are much less justified without a nexus to health benefits from reductions of HAPs. In fact, EPA's benefit-cost analysis in the regulatory impact analysis did not include any quantification of health benefits from HAP reductions. EPA should factor its CAA Section 112(f)(2) findings into its technology cost analysis.

## V. EPA's MATS Technology Review should be revised to accurately reflect the current state of technology and capabilities of the nationwide EGU fleet.

APPA incorporates the technical evaluation for this Proposed Rule entitled "Technical Comments on National Emissions Standard for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology" (Technical Report).[26] This analysis reviews EPA's basis to support its decisions in the Technology Review by examining EPA's inventories, emissions review, model, and cost-effectiveness calculations.

### A. EPA's fPM Analysis is flawed and must be corrected.

[25] *Id.* at 24865.
[26] Cichanowicz et al., Technical Report on National Emissions Standard for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology, June 19, 2023, attached as Appendix A.

1. <u>General Considerations.</u>

The Proposed Rule concluded that there are "no new practices, processes, or control technologies for non-Hg HAP."[27] Irrespective of this finding, EPA pressed on to identify "developments" that are the basis of EPA's decision to make changes to the fPM standard.[28] Developments identified in the Proposed Rule are: (1) Most EGUs are reporting fPM levels below the current emission limit; and (2) Performance levels are achievable at lower costs than originally assumed.[29] EPA proposed a reduction in the fPM emissions limit from 0.030 lb/mmBtu (current) to 0.010 lb/mmBtu (recommended), a reduction of more than one-half. EPA even suggests that the limit should be reduced further to 0.006 lb/MMBtu. EPA prepared technical analyses for both standards and rejected a reduction to 0.015 lb/MMBtu. EPA rejects 0.015 lb/MMBtu simply because "it would largely leave in place the status quo," adding an arbitrary bias as discussed in Part III of these comments.[30]

As general considerations, EPA should consider that ESPs are proven technology but not all EGUs are equivalent by unit design, fuel variability, and other unique considerations. Costs and availability of upgrades will also vary. For example, space constraints may limit the availability of certain ESP upgrades. Applying an emissions limitation that is too low will not allow for unit variability. For these reasons, APPA supports a revised fPM emissions limitation based on corrections to the fPM baseline and cost analysis but, in no event, lower than 0.010 lb/mmBtu.

APPA does not support lowering the fPM limit to 0.006 lb/mmBtu for feasibility and cost considerations across the industry and particularly in the public power sector. A significant number of units cannot meet this stringent emission rate.[31] EPA concludes that units without baghouse technology, such as ESP-only units, would need to install a baghouse (fabric filter technology) to achieve 0.006 lb/mmBtu. Cost implications are particularly significant for public power entities that have limited financing resources and budget constraints based on operating revenue, as discussed in Section V.C. Baghouse technology is estimated to cost $282,715 per fPM ton.[32] The only improvement would be the incremental improvement from ESP control to baghouse control, further driving up the cost in terms of dollars per ton ($/ton). The cost of that retrofit project will force unit retirements in an already burdened sector. Grid reliability will be compromised.

EPA seeks comment on the impacts of the fPM standard on overburdened communities. EPA asks for consideration "of 6.0E-03 lb/MMBtu or a more stringent standard considering the higher emission reductions, as well as the larger total costs such a standard would entail to inform our consideration of whether the more stringent

[27] *Id.* at 24,868. This is the statutory foundation of the technology review.
[28] *Id.*
[29] *Id.*
[30] Proposed Rule at 24,871.
[31] Technical Report at Section 4.1.3 ("More than 1/3 of the units with ESP/wet FGD and ¼ of ESP- only cannot meet this rate, with fabric filter either operating with dry FGD (20%) or alone (16%) not achieving this target. Almost 20% of those with FF/wet FGD units emit greater than this value.").
[32] This value from our Technical Report is further discussed in Section V.B.2 of these comments.

standard would reduce the overall pollution burden in these communities." Of critical significance, EPA must recognize and applaud the power sector for reducing the overall air toxics risk to acceptable standards. Industry-reported emissions data, required by MATS, shows 2021 mercury emissions from coal-fired EGUs were 90 percent lower than pre-MATS levels. Since 2010, acid gas HAP emissions have been reduced by over 96 percent, and emissions of the non-mercury metals – including nickel, arsenic, and lead – have been reduced by more than 81 percent.[33] The Proposed Rule confirms that there are no unacceptable risks posed by this sector. This conclusion relies on the emissions reductions at the current fPM limit of 0.030 lb/mmBtu and takes into account vulnerable communities. However, the proposed fPM measures come with a sizable price tag that all communities must shoulder. EPA must weigh the costs of imposing these emissions reductions in areas supplied by public power in which the customer will face higher electricity costs. Nationally, low-income households spend a larger portion of their income on home energy costs (e.g., electricity, natural gas, and other home heating fuels) than other households spend.[34]

2. fPM Technical Comments.

The Technical Report reviews EPA's underlying evaluation that supports its proposal to lower the fPM emissions limit. As presented *infra*, EPA's evaluation has significant flaws. While EPA's technical analysis does not have to be "flawless," it must be reasonable. EPA misses this mark.[35] Consequently, EPA should revisit its analysis before adjusting the fPM emissions limitation to any degree.

EPA's analysis of fleet-wide fPM emissions has so many shortcomings that the output is a biased set of results as to its analysis of baseline emissions, costs, and compliance repercussions. Since this analysis is the fundamental basis of EPA's "developments" for fPM, including EPA's cost/ton analysis, it must be revised.

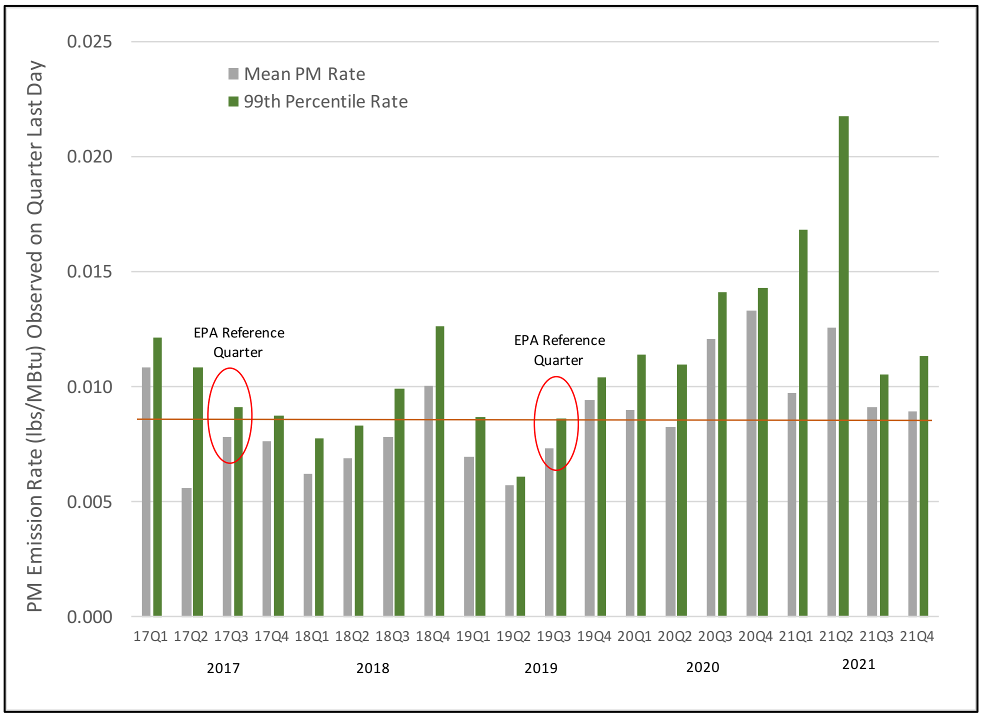
(a) EPA's fPM Database.

EPA's fPM emissions database is sparse. It includes selective PM CEMS and stack test data from sources for 2017, 2019, and 2021 from at least six reference years of data available to EPA.[36] EPA employs a different data selection methodology for each of those years and based on type of compliance measure used (CEMS vs. stack test).[37] Only nine units were included in the dataset in 2017 and 187 in 2019. In 2021, 41 units were incorporated.[38] Datapoints included in the EPA database to create fPM baselines are limited in number and in years. EPA has unit fPM emission data in its possession and should use these data.

[33] 2021 Power Sector Programs Progress Report; available at https://www3.epa.gov/airmarkets/progress/reports/pdfs/2021_full_report.pdf
[34] https://www.energy.gov/sites/prod/files/2019/01/f58/WIP-Energy-Burden_final.pdf
[35] *Sierra Club v. EPA*, 167 F.3d 658, 662 (D.C. Cir. 1999). The Court asks if EPA acted "reasonably" and not "flawlessly." *NRDC*, 529 F.3d at 1086.
[36] Technical Report at Section 1.
[37] *Id.* at Section 3.2.2. Less CEMS monitoring data was included.
[38] *Id.*

EPA makes faulty assumptions that intentionally push the fPM emissions baseline lower. EPA selects the lowest fPM rate from selected reference quarters.[39] EPA justifies this selection by indicating that these lower fPM rates account for the actions that the utility has taken to lower emissions. However, EPA mistakenly assumes that the process conditions that enabled those best-case rates are possible at all times. This assumption is not supported by the data or explained by EPA in the Proposed Rule. Therefore, EPA holds EGUs to a standard that cannot be consistently achieved. EPA's methodology cherry-picks the lowest fPM rates, yielding an unrealistic baseline. Figure 3-4 illustrates this approach with respect to Coronado Generating Station Units 1 and 2.

Figure 1 Technical Report, Figure 3-4 Coronado Generating Station: 16 Operating Quarters




Looking at the Coronado PM CEMS data, EPA's reference quarters between 0.010 and .005 lb/mmBtu are not representative of the fPM baseline. Eleven of 20 quarters reported fPM data higher than those used in the database. The Coronado operator reports that quarter three of 2019, which is used in EPA's dataset, reflects normal operation without any maintenance or optimization activities that could have impacted emissions during that quarter. Rather, the measurement is representative of normal unit variability.[40]

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[39] *Id.* at Section 3.2.4.
[40] Technical Report at 3.2.4.

Similarly, EPA deliberately biased its baseline from PM CEMS data low. Instead of using all PM CEMS data, EPA arbitrarily selected quarters of PM CEMS data and relied on 30-day averages observed on the last day of the quarter. This approach also ignores the natural variability of unit operation.

(b) Stack Test and CEMS data in the fPM database.

EPA's database includes emissions reported from CEMS and performance tests.[41] Stack tests directly measure PM by calculating the mass of PM and the volume of flue gas from which that mass of PM was sampled. PM CEMS measure indirect properties such as light scatter or beta attenuation. Direct and indirect measurements of fPM may lead to different results, which may compromise accuracy of the database especially at low levels of fPM. We note that the EPA database contains predominantly stack test data. If EPA decides to move to a PM CEMS-only approach, the database should be based only on independent PM CEMS measurements[42] to correct for any bias caused by the direct measure of fPM by stack testing.

(c) Variability in seasonal operations and unit configuration.

Review of fPM data consistently shows variability in process operations. These variations may be due to coal composition, seasonal load, or operational conditions. By using a statistical approach, EPA capriciously ignores that factors unrelated to control technologies result in lower fPM values, not just improvements in control of fPM. It is revealing that EPA identifies lower emissions data but does not equate that data to any actual new fPM "practices, processes, or control technologies" since 2012 or 2020. The record does not identify or discuss technological or operational advances in ESP technology or operation. In fact, ESP technology may not have improved. The lower fPM baseline may be purely due to EPA's biased fPM monitor selectivity and statistical manipulation.[43]

In addition, variability in individual EGU configuration plays a significant factor in fPM emissions performance. EGUs vary in their control technology trains and order of control devices prior to measurement of flue gas in the stack. These dissimilarities have measurable fPM results. Units with ESPs, whether alone or with a flue gas desulfurization (FGD), report the highest fPM rates as compared to other EGUs. Meanwhile, units with baghouses (fabric filters), whether alone or with a wet or dry FGD, have lower fPM rates.[44] EPA should take the differences in the EGU population into consideration by featuring a compliance cushion to give ESP-only units more margin to

[41] Technical Report at 1.
[42] EPA applies the Excel PERCENTILE function to ninety 30-day rolling averages in a given quarter. Each 30-day rolling average is highly correlated to the previous 30-day average given that each 30-day rolling average will include 29 of the same values as the previous average. EPA incorrectly analyzes correlated data with a function that assumes the data are independent. This analysis underestimates variability. The more correlated the data, the more the degree of underestimation. Thus, the purported 99th percentile values are not 99th percentile values at all.
[43] *See* discussion in n.44 *supra* regarding data manipulation to yield a value that is not a 99th percentile.
[44] Technical Report at Section 4.1.3.

operate. Additionally, it is well known within the industry that ESPs cannot reach full control efficiency until well after startup due to safety issues. This startup issue has not been considered and is not reflected in stack test data.

(d) EPA's cost analysis for fPM.

The Technical Report finds meaningful errors in EPA's cost analysis that must be corrected. The errors lead to sizeable cost-per-ton underestimates that erode EPA's overall assumption that the proposal is cost-effective.

EPA must add a compliance margin in its achievability assumptions. EPA misjudges the number of EGUs that must undertake retrofits by failing to factor in a compliance cushion. EPA has long recognized that a design/compliance margin is needed due to operational variability and recognized this concept in the context of the original MATS technology analyses.[45] A margin of at least 20% is the industry standard and identified in the 2012 Control Needs Memo.

In the cost analysis, EPA did not assign a design/compliance margin. By making this choice, EPA underestimates the number of units that require retrofits. The Technical Analysis revises the cost analysis to adjust the number of units requiring upgrades to a total of 26 ESPs to meet 0.010 lb/mmBtu and projects a much higher project cost based on actual project build cases.[46] To achieve 0.006 lb/mmBtu, 52 ESP-equipped units would need to retrofit to a baghouse, and 23 units with baghouses would need to adopt an enhanced operation and maintenance (O&M) protocol, increasing EPA's estimate (65 versus 87).[47] The cost per ton value is considerably higher with the additional retrofits and higher project costs, resulting in a very significant cost difference, as summarized in this table:

| **fPM Proposed Rule rates** | **EPA average cost/ton** | **Technical Report average cost/ton** | **Notes** |
|---|---|---|---|
| 0.010 lb/mmBtu | $37,300-$44,900 | $67,262 | *The Technical Report's cost per ton increases result from inclusion of additional units to require retrofit for both fPM incremental decreases.* |
| 0.006 lb/mmBtu | $103,000 | $282,715 | |

We also note that EPA's deflated and unrepresentative fPM baseline is not accurate and therefore it is not possible to project the number of units that will need upgrades. Therefore, APPA requests that EPA revise its cost analysis after it reevaluates its

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[45] Hutson, N., National Emission Standards for Hazardous Air Pollutants (NESHAP) Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired Electric Utility Steam Generating Units, Memo to Docket No. EPA-HQ-OAR—2009-0234, November 16, 2012 (the 2012 Control Needs Memo) at 1 (discussing mercury); 2 (discussing PM).

[46] *Id.* at 5.2.1 (discussing 4 documented cases of ESP rebuilds in Table 5-2).
*Id.* at 5.2.1 (discussing 4 d

baseline data and then apply at least a minimum of 20% compliance margin in the cost analysis to adequately reflect the number of units that would need to undertake fPM control upgrades.

(e) APPA's Recommendations.

Based on the Technical Comment findings, APPA suggests that EPA must revise the fPM database as follows:

- Include all data points from EGUs in its dataset for each year;
- Use at least five years of fPM data;
- Use fPM datapoints that are representative of all unit operation rather than using best-case, lowest fPM values that do not take unit variability into consideration;
- Refrain from using statistical approaches and assumptions to account for variability in fPM performance; and
- If EPA eliminates performance testing as a compliance option, EPA should rely exclusively on a robust set of statistically independent PM CEMS data (such as daily values that will not underestimate unit variability) in terms of number of units and datapoints used. This decision will rectify concerns that PM CEMS data has a high bias as opposed to stack test data.

Overall, EPA should investigate why EGU fPM rates differ in a given year rather than assuming that the lowest value can be consistently achieved. This analysis will help EPA determine if any of the fPM data is truly indicative of new practices, processes, or control technologies – rather than data mining and normal operational variability.

If EPA's revised analysis indicates fPM emission rate should be adjusted, EPA should consider the variability in the nationwide EGU fleet on an annual basis at the same unit and within the fleet based on the emission control train. Margin should be built into the standard to account for this variability.

**B. The time frames for fPM improvements in the Proposed Rule cannot be met by many public power entities.**

EPA sets a three-year deadline from the forthcoming final rule's effective date to comply with the new MATS emissions limitations. EPA asks for comments on whether an additional year is needed for emissions limitation compliance. APPA advocates for an additional year for fPM emissions limitation compliance for the reasons identified in this section.

1. <u>Unique consideration of public power entities.</u>

EPA must take the unique attributes of small entities into account when setting the time frames required for the installation of fPM upgrades or new controls. Public power entities have specific parameters, unlike most investor-owned utilities. Many municipalities have special financing restrictions and guidelines.

Small utilities frequently finance capital power plant projects using income generated from the sale of power from their generating assets. This revenue is limited, causing these public power entities to stagger projects based on revenue availability. Emergency municipal funds are sometimes used in lieu of operating funds. However, these reserves are also limited. Outages must also be taken sparingly. When a unit is down, it is not generating revenue, and the municipality must cover the loss of generation. The income stream from the unit is essential so that the public power entity can pursue the environmental projects required for compliance.

Single plant and unit owners are also limited in the ability to finance loans and bonds due to limited collateral. Public power entities must have the revenue to pursue the projects EPA contemplates. Revenue availability impacts the timing of projects. In addition to this Proposed Rule, EPA's suite of other environmental regulations for greenhouse gases, effluent limitations guidelines, ozone season NOx, and coal ash also require significant expenditures within the same time period (2025-2030).[48]

In addition, many public power entities are required to engage in a bidding process when undertaking substantial construction projects, such as what the Proposed Rule contemplates for fPM control upgrades and installations. The bidding process often takes at least six months from the issuance of bids to the award to the successful participant.

EPA must consider the financial constraints and requirements unique to public power entities when setting compliance deadlines for this Proposed Rule.

2. <u>Limited availability of vendors to perform fPM upgrades.</u>

APPA has concerns regarding workforce availability. There are not enough vendors that can perform fPM upgrade projects or install new fPM controls. Our Technical Report estimates that 26 units will be required to upgrade ESPs if EPA sets the fPM emissions limit at 0.010 lb/mmBtu. This number grows substantially to 52 ESP-controlled units that would need to retrofit to a fabric filter if the limit dips to 0.006 lb/mmBtu.[49]

EPA's three-year timeline is not workable due to the length of project time for some ESP upgrades and all new fabric filter installations. We estimate that these time frames, which include design, procurement, commissioning, construction, and startup, based on our members' project experience:

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[48] The Fall Unified Agenda projects the final MATS RTR rule to be released in March 2024. Using this date, sources would need to comply with the new limitations/compliance method revisions by Spring 2027 (3 years).
[49] Technical Report at 5.2.2.

- Major ESP rebuilt projects: At least 36 months (3 years)
- ESP conversion to Fabric Filter: At least 48 months (4 years)
- New Fabric Filter: At least 48 months (4 years)

The estimated time frames do not account for vendor availability. At present, the vendor workforce that performs ESP retrofits and installations of fabric filters is limited. We believe there are only about four active vendors in the United States market.

In summary, APPA requests that EPA provide at least an additional year and an option to apply for a need-based extension based on project timing constraints or financial limitations. EPA may also consider deferring the Final Rule's effective date to provide more timing flexibility for projects.

**C. The fPM cost per ton is unduly burdensome for small power generation operators such as public power entities.**

EPA does not give adequate consideration to the cost impacts of the Proposed Rule on public power entities. As presented above, public power entities have limited financial resources and assets to leverage. If public power entities are unable to finance ESP upgrade projects, their only choice is to shut down. Loss of power to America's cities powered by our members is an unacceptable option. EPA should consider the specialized impacts on smaller utilities, which it has done in other RTR reviews.[50]

Last year EPA rejected other technologies based on cost per ton. For example, in the Proposed Rule for Bulk Gasoline Terminal NESHAP, EPA found: "The cost-effectiveness and incremental cost-effectiveness of reducing the area source emission limit for large bulk gasoline terminals to 10 mg/L are approximately $12,000 and $13,000 per ton of HAP emissions reduced, respectively, which we determined is not cost-effective." In comparison, even EPA's cost per ton estimates for the Proposed Rule is far above this level (starting at $37,300).[51]

EPA makes the determination, "that there is not a significant economic impact on a substantial number of small entities."[52] EPA estimates that 26 small entities [are] affected by the rule, and of these, three small entities may experience costs of greater than 1 percent of revenues."[53] However, according to EPA's analysis, none of the potentially affected small entities identified were public power utilities. APPA believes this analysis is flawed. Based on APPA's review of the affected units, we have identified the following facilities as small entities based on the population of the

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[50] For example, the D.C. Circuit affirmed EPA's decision to reject the installation of HEPA filters that would have resulted in greater economic impacts to small businesses. *NASF*, 795 F.3d at 10.

[51] 87 Fed. Reg. 35608 (Jun 10, 2022); *see, e.g.*, *U.S. Sugar Corp. v. EPA*, 830 F.3d 579, 642 (D.C. Cir. 2016) (affirming EPA's decision that stricter carbon monoxide control measures were not cost-effective at $26,000 per ton).

[52] Regulatory Impact Analysis for the Proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review at page 5.8 (RIA).

[53] *Id.*

communities served: Muscatine Power, Manitowoc Public Utilities, and Sikeston Utilities. EPA should re-evaluate its analysis to include the significant impacts of this Proposed Rule on all small entities, including public power entities.

### D. The option for performance testing for direct measurement of non-Hg metal HAPs should not be removed.

EPA proposes to eliminate individual and total non-Hg metals emissions limits altogether. EPA would remove the option in the current rule to stack test for individual and total non-Hg. EPA comments that only one owner, to EPA's knowledge, uses non-Hg metals data to comply. EPA's sole justification for removal of individual and total non-Hg metals emissions limits is to simplify the rule.

Simplicity is not an adequate justification to remove the non-Hg metals compliance alternative. These are the HAPs that form the entire basis for the non-Hg portion of the Rule. It is legally questionable whether EPA can remove a direct measurement alternative and what authority EPA has to do so.[54] We observe that if EPA makes a substantial change to the fPM emissions limitation, more sources may opt for direct HAP measurement. These HAPs are the pollutants to be reduced, so it is inappropriate to remove this option. EPA has provided no reasonable justification to remove this flexibility from the MATS Rule.

### E. APPA supports EPA's decision to retain the current mercury standard for bituminous coal units and non-lignite units.

APPA supports EPA's decision to retain the current mercury limitation for bituminous coal-fired boilers and other non-lignite units. EPA's analysis and verification of the low average annual Hg rate of 0.4 lb/TBtu (bituminous) and 0.6 lb/TBtu (subbituminous) support this decision. We appreciate EPA's observations of the technological control capabilities based on the "leveling off" effect present in control technology performance curves as solvent increases but reductions in mercury diminish. The mercury rate for these units is already at a very low level. It is also necessary to provide a compliance margin, given the variability of coals and unit operating conditions. APPA supports retaining the current standard.

APPA is not in favor of the substantial mercury limit reductions that EPA seeks to impose on lignite units. APPA incorporates the comments in the Technical Report on this topic, which critiques EPA's analysis for lignite units.

### F. The Acid Gas and Organic HAP Work Practice Standards should be retained.

APPA acknowledges and agrees with EPA's findings to retain the standards for acid gases. Our members use FGD systems and reagent injection to reduce acid gas (HCl and HF). We are unaware of any new control technologies or improvements.

[54] EPA makes this recommendation outside of the Technology Review process.

Organic HAP work practice standards should also be retained without change. We agree with EPA's conclusions that there are no new developments in technology or methods of operation that would result in cost-effective emission reductions.

**G. EPA should retain Startup Definition 2.**

EPA proposes to remove startup definition 2 as an alternative work practice standard. This option requires the use of clean fuel to the maximum extent possible, operation of PM control devices within 1-hour of introduction of primary fuel to the EGU, recordkeeping, and exclusion of recorded values from numeric emissions standards within 4 hours of the generation of electricity for sale to the grid or thermal energy for use on-site.[55] To justify removal, EPA comments that most EGUs have not used this definition. EPA states that startup definition number 1 is achievable by most the fleet and claims that few costs would apply to this change.

APPA's members are impacted by EPA's proposal to remove this flexibility. Like other alternatives that EPA proposes to remove, simplicity is not an adequate justification. EPA notes that the best performing 12-percent of sources do not need this alternative.[56] However, EPA conflates the MACT standard-setting process with this RTR process. This change is beyond the scope of the technology review, and regardless, the 12-percent standard should not be misapplied. From a practical standpoint, we also note that startup definition 2 may be availed by more sources in the future if EPA sets a lower emissions limit that pushes sources to the brink of their fPM control technology capabilities. The fPM baseline does not fully capture emissions immediately following startup and shutdown, given that EPA's database includes predominantly stack test data collected during normal operating conditions. As a result, EPA's baseline does not adequately reflect to what extent sources would need more flexibility during startup to achieve a lower fPM limitation. APPA supports retaining startup definition 2, or at a minimum, allowing sources with retirement commitments to continue to use definition 2.

EPA may also consider allowing the use of diluent cap values from 40 CFR Part 75 procedures. Startup and shutdown variations are more pronounced due to the MATS rule's limited use of diluent cap values. With a lower emissions limitation, the diluent cap would mathematically correct for calculation inaccuracies inherent in emission rate calculation immediately following startup.[57]

As EGUs transition to renewable assets, startups may become more frequent due to fossil unit cycling to support intermittent generation. The changes in baseload unit behavior – which may lead to more startups – should be supported. Keeping startup flexibilities in this Proposed Rule will support the fleet transition to lower greenhouse gas emissions by supporting renewable generation.

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[55] Proposed Rule at 24,885-86.
[56] *Id.* at 24886.
[57] PM Monitoring Report at Section 7.

## VI. The proposed revisions to fPM compliance measures and PM CEMS procedures are problematic.

There is no statutory justification for revising monitoring equipment and changing monitoring methodologies in an RTR. Our members currently avail themselves of compliance flexibilities built into the MATS Rule. It would substantially affect public power entities if EPA eliminated these avenues and monitoring changes that lengthen correlation testing. In this section, we outline specific reasons why EPA's monitoring proposal should be revised.

### A. fPM Performance Testing and PM CPMS should not be eliminated as compliance methods.

EPA proposes to eliminate fPM quarterly stack testing as an option, leaving PM CEMS as the sole method of compliance for most EGUs. This proposal significantly impacts the nationwide fleet, including many APPA members that use fPM stack testing and PM CPMS for compliance. EPA estimates that only a third of EGU owners and operators use PM CEMS for compliance purposes.

When EPA promulgated the MATS Rule, EPA acknowledged that "[t]he EPA believes the requirements of the final rule have been made as flexible as possible consistent with the CAA."[58] But here, EPA departs from its own acknowledgment of the spirit of the CAA. Further, EPA identifies no measurable air quality benefit behind these changes. We seek EPA's reconsideration of this portion of the proposal for the following reasons.

1. <u>PM CEMS lack accuracy.</u>

EPA makes an assumption that PM CEMS are reliable at low levels below 0.010 lb/mmBtu. However, no evidence is present to justify the validity of measurement at such low levels of fPM. Vendors identify a PM CEMS detection limit of <1 mg/m3, but that detection is meaningless until it is correlated to reference method data during the PS-11 correlation test. Few PM CEMS are currently used to comply with levels at or below 0.010 lb/mmBtu and PM CEMS response at these levels has not been adequately demonstrated. A recent Electric Power Research Institute (EPRI) study results call into question whether currently operational PM CEMS can achieve passing results consistently due to the high failure rate observed (44% of the current PM CEMS are not meeting +/- 1.5 mg/m3).[59] Wet stacks have additional challenges during correlation testing at low fPM levels, likely due to scrubber carry-over impacts on fPM measurement.[60]

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[58] 77 Fed. Reg. 9304, 9417 (Feb. 16, 2012).
[59] Particulate Matter Continuous Emission Monitoring System Quality Assurance Test Evaluation, EPRI, Palo Alto, CA: 2022. 3002027695.
[60] PM Monitoring Report at Section 3, which discusses PM CEMS correlation test and measurement challenges at low fPM levels.

2. fPM stack testing is a tried and true measure of compliance used in other Section 112 standards.

EPA has not provided an adequate justification for removing stack testing, particularly in light of the shortcomings of PM CEMS and the costs associated with them. Section 112 standards do not have to employ continuous emissions monitoring.[61] As long as the compliance measure is a reasonable assurance of compliance with the emissions standards, that standard is acceptable. The court in *Sierra Club* stated that "[t]here is no presumption in favor of any particular type of monitoring."[62] EPA has successfully argued that stack testing is an appropriate compliance method.[63]

EPA justifies removal of stack testing by stating that PM CEMS have the benefits of "increased transparency and accelerated identification of anomalous emissions."[64] However, in the final 2012 MATS rulemaking, EPA stated: "We believe that continuous monitoring in the form of CEMS, sorbent trap monitoring systems, and PM CPMS, or *frequent stack emissions testing* are appropriate to ensure ongoing compliance with this final rule."[65] EPA further justifies widespread use of PM CEMS by stating that the current one-time costs for PM CEMS has decreased making their use even more cost effective. This statement is not correct based on vendor quotes from instrument manufacturers, CEMS integrators, stack testers, and APPA members. No meaningful technology or monitoring changes have occurred since 2012 that would disqualify stack testing. Quarterly monitoring is a sufficient frequency to assure compliance, consistent with EPA's findings in 2012. We also note that many units have other parametric methods for compliance with other standards, such as continuous opacity monitoring systems (COMS) for opacity measurement, that are used as compliance indicators.

3. The LEE option should also be retained along with stack testing.

Units that choose to stack test and attain low fPM levels should be rewarded with a lower frequency of testing (current 3-year testing frequency) for MATS. These units are frequently subject to annual PM testing to satisfy other regulatory requirements in their Title V permits. Many continue to perform annual stack tests for permit compliance. COMS or other parametric monitoring may be a feasible tool to ensure that the operations of the EGU remains consistent with those during the performance test.[66]

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[61] *Sierra Club v. EPA*, 353 F.3d 976, 990-91 (D.C. Cir. 2004).
[62] Id. at 991.
[63] *See White Stallion Energy Ctr v. EPA*, 748 F.3d 1222, 1255 (D.C. 2014) (reversed on other grounds) (affirming stack testing in 2012 for EGUs in response to EPA's position that quarterly stack tests were sufficient to assure compliance).
[64] Proposed Rule at 24857.
[65] 77 Fed. Reg. at 9420 (emphasis added) (response to comment on monitoring choices).
[66] See 63.10005(b)(5)).

4. Limited compliance staff resources make compliance with detailed PM CEMS requirements challenging.

Municipalities and public power have limited environmental staff. PM CEMS operations require intensive training and knowledge of the detailed provisions of 40 CFR Part 60 Appendix B and Appendix F.[67] The detail involved frequently requires our members to seek assistance from specialized contractors that regularly address the installation, operation, maintenance, and accuracy testing for CEMS. Skilled technicians are often needed to perform the required PS-11 correlation. These costs add to the overall compliance tab. For resource and staffing reasons, some public power entities opt to use stack testing for compliance. Retaining a stack testing alternative is meaningful for these entities and should not be removed.

5. PM CEMS correlation testing causes more fPM emissions.

EPA should take account of the increased air emissions caused by PS-11 correlation testing required for PM CEMS calibration. PS-11 and Procedure 2 response correlation audits require detuning of control systems to obtain elevated PM conditions for the test. We anticipate that additional correlations will be necessary with a lower fPM limit. In addition, meeting the requirements of PS-11 (as required both initially and routinely in the case of relative correlation audit (RCAs) that fail to meet the requirements of Procedure 2) will be even more difficult with a lower fPM limit, as the tolerance interval criteria depend on the applicable emission limit. Therefore, elevated fPM conditions during testing are likely to increase in duration from the status quo.

In addition, PM CEMS quality assurance testing requirements sometimes cause units to “force run” that would otherwise not be dispatched by an RTO/ISO. To complete these tests, a unit will sometimes operate in a negative pricing market. This “force run” dispatch may cause the curtailment of non-fossil assets and, therefore, higher fossil emissions and costs to operators.

In comparison, stack testing does not require detuning of control equipment, resulting in less impact on the environment. Stack testing also does not “force run” units to operate to complete testing. EPA should consider these air quality benefits of stack testing.

6. Cost is a significant factor for public power.

Cost is a substantial consideration of APPA members. Members would be required to pay the capital cost to install PM CEMS and operate them. PM CEMS are more expensive than stack testing. PM CEMS costs are composed of the one-time equipment and installation cost and annual operation costs. EPA underestimates both.

[67] MATS Appendix C references Part 60, Performance Specification 11 (PS-11) for initial certification and Part 60, Appendix F, Procedure 2 for ongoing quality assurance (QA/QC) requirements.

Our Particulate Monitoring technical comments provide detailed responses to EPA's cost analysis (RTP Particulate Monitoring Technical Report). A summary is presented below.[68]

*Figure 2 RTP Particulate Monitoring Technical Report Table 3 PM CEMS One-Time and Annual Costs*

| Data Source | PM CEMS type | Annual costs, $ | | | | EUAC, $ |
|---|---|---|---|---|---|---|
| | | Capital recovery[69] | Operation and maint. | Audits | Other annual costs | |
| EPA MCAT | In situ | $ 22,016 | $ 1,558 | $ 54,877 | $11,219 | $ 89,670 |
| | Extractive | $ 25,700 | $ 2,579 | $ 54,877 | $12,241 | $ 95,397 |
| EPA CEMS Cost Model | In situ | $ 15,912 | $ 2,689 | $ 54,392 | $6,525 | $ 79,518 |
| | Extractive | $ 20,300 | $ 3,689 | $ 54,392 | $7,525 | $ 85,906 |
| Average | - | $ 20,982 | $ 2,629 | $ 54,635 | $9,378 | $ 87,623 |
| ICAC | Low | $ 3,843 | $ 12,000 | $ 14,290 | $ - | $ 30,133 |
| | High | $ 4,392 | $ 12,000 | $ 14,290 | $ - | $ 30,682 |
| Envea/ Altech | Dry | $ 3,821 | $ - | $ 14,290 | $ - | $ 18,111 |
| | Wet | $ 13,020 | $ - | $ 14,290 | $ - | $ 27,310 |
| Average | - | $ 6,269 | $ 12,000 | $ 14,290 | $ - | $ 32,559 |
| ***This Study*** | | | | | | |
| Sick FWE200DH | Extractive | $ 27,225 | $ 22,500 | $ 54,850 | | $ 104,575 |
| | | $ 32,725 | $ 22,500 | $ 79,850 * | | $ 135,075 |
| Sick SP100 | In-Situ | $ 19,525 | $ 18,900 | $ 54,850 | | $ 93,275 |
| | | $ 25,025 | $ 18,900 | $ 79,850 * | | $ 123,775 |
| PCME 181WS | Extractive | $ 28,721 | $ 22,500 | $ 54,850 | | $ 106,071 |
| | | $ 34,221 | $ 22,500 | $ 79,850 * | | $ 136,571 |

[68] RTP Environmental Associates, Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology, June 22, 2023, attached as Appendix B.
[69] One-time costs are provided in more detail in the RTP Particulate Monitoring Technical Report, Table 1. Capital costs incorporate this value.

| | | | | | | |
|---|---|---|---|---|---|---|
| PCME 181 | In-Situ | $ 21,406 | $ 18,900 | $ 54,850 | | $ 95,156 |
| | | $ 26,906 | $ 18,900 | $ 79,850 * | | $ 125,656 |
| TML LaserHawk 360 | In-Situ | $ 19,195 | $ 18,900 | $ 54,850 | | $ 92,945 |
| | | $ 24,695 | $ 18,900 | $ 79,850 * | | $ 123,445 |
| BetaGuard 3.0 | Extractive | $ 35,585 | $ 33,700 | $ 54,850 | | $ 124,135 |
| | | $ 41,085 | $ 33,700 | $ 79,850 * | | $ 154,635 |
| Average | - | $ 28,026 | $ 22,567 | $ 67,350 | | $ 117,943 |

*Audit costs include PM spiking by ash injection during RCAs presumed to be necessary every other year.

(a) <u>PM CEMS One-Time Costs</u>

EPA claims that the cost of PM CEMS devices has reduced 48% from average comparable costs determined from EPA's cost/benefit analysis tool (MCAT). As presented by RTP's Table 3, quotes from EGU owners and operators show larger capital costs associated with the actual instrument, installation, and integration of the CEMS, in particular for extractive PM CEMS which must be used following wet scrubbers.

(b) <u>PM CEMS Annual Operation and Maintenance Costs</u>

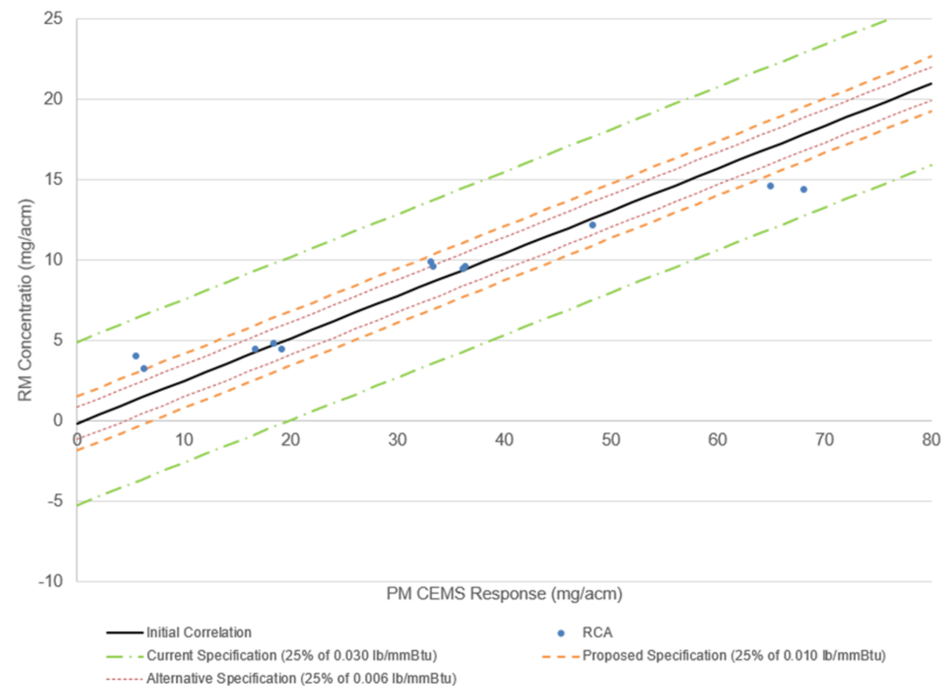
Annual PM CEMS costs include capital recovery, operation, and maintenance, CEMS audits, and other miscellaneous operational costs. Of the annual costs, audits are the most expensive item. EPA underestimates audit costs to a large degree in Proposed Rule, Table 4, by underestimating costs for all of the audit testing that must occur and ignoring more frequent RCAs tests due to unsuccessful relative response audit (RRAs) at the reduced fPM emission limitation.

MATS Rule Appendix C addresses the QA/QC requirements for PM CEMS. It incorporates by reference 40 CFR Part 60, Appendix F, Procedure 2 (Procedure 2), and 40 CFR Part 60, Appendix B, Performance Specification 11 (PS-11). Sources must perform a RRA once every four calendar quarters and a RCA once every twelve calendar quarters for quality assurance (QA) of their PM CEMS.

The Proposed Rule omits the costs for all of these QA tests. EPA included only the annual cost for filterable PM spiking once every 3 years. The cost of conducting RRAs is equivalent to the cost of a single filterable PM quarterly test or triennial LEE test for PM. The cost of conducting RCAs is much greater since it must incorporate additional test runs, careful oversight, and control device detuning and/or PM spiking.

EPA should recognize that if the MATS fPM rate is reduced to 0.010 lb/mmBtu or lower than the frequency of RCAs will increase significantly. RCAs must be performed if an RRA does not meet specifications. A more stringent fPM limitation will result in more QA test failures because the pass/fail specification for tests are expressed as a percentage of the fPM limit. The following Figure 3 depicts the much narrower band that an instrument must achieve to “pass” due to the percentages calculated using the lower fPM limitations.

*Figure 3 RTP Particulate Monitoring Technical Report Figure 3*




Plainly, more RCAs will occur due to RAA failures than are presently needed for the 0.030 lb/mmBtu standard. The RTP revised cost estimate in this Section accounts for the failure rate reported in the EPRI study identified in the RTP Particulate Monitoring Technical Report.

The costs and operational burden of these devices do not justify their benefits. As previously identified, PM CEMS have many shortcomings that we request EPA factor into its analysis. APPA requests that EPA consider the cost information presented in the RTP Particulate Monitoring Technical Report and re-evaluate its cost estimates.

(c) Quarterly fPM Stack Testing

EPA overestimates the cost of conducting quarterly fPM stack tests. Our cost annual comparison is:

*Figure 4 Stack Testing Costs*

| Task | Proposed Rule | RTP Report |
|---|---|---|
| Stack Test | $85,127 ($20,500 plus $782 for site support per quarterly test)[70] | $58,240 ($13,000 plus $1560 for site support per quarterly test) for 3 test runs at a volume of 4 dscm per run based on vendor information |

Obviously, LEE units may reduce these costs by a factor of three. In addition, a large number of sources conduct quarterly or triennial testing to demonstrate compliance with the HCl emission limitation. Currently, 166 stack IDs rely on a combination of quarterly (or triennial) HCl testing. The incremental cost when adding a fPM test during the same mobilization as HCl testing is minimal.

7. PM CPMS should be retained as a compliance option.

APPA supports retaining PM CPMS as an option to show continuous monitoring data to comply with fPM standards. Continued use of PM CPMS will avoid the burden of maintaining a certified PM CEMS, while providing an accurate compliance indicator. In 2012, EPA justified the use of PM CPMS to offer flexibility to EGUs with these devices. There have not been any meaningful developments to justify removing this option.

In 2012, EPA stated:

> In order to provide flexibility in the final rule, we have retained a source's ability to define an operating limit and to monitor using a PM CPMS as an option to periodic filterable PM emissions testing . . . . [W]e also are aware that other rules that apply to these units including, but not limited to, the Operating Permits rule, the Compliance Assurance Monitoring rule, the ARP rules, and the NSPS already require continuous monitoring in most cases. Those rules will remain in effect so the need to impose additional operating limits monitoring or CEMS on those units is much reduced.[71]

We appreciate EPA's recognition that these EGUs have other rules that, cumulatively, with MATS, are sufficient to ensure continuous compliance. EPA has presented no data to suggest that PM CPMS are no longer effective.

[70] RTP Particulate Monitoring Technical Report at Section 4.
[71] 77 Fed. Reg. at 9420 (response to comment on monitoring choices).

PM CPMS provide effective and continuing compliance assurance information. PM CPMS establish operating limits, which are verified on an annual basis. These limits trigger corrective actions if they are exceeded. In this way, the current MATS CPMS provisions provide for quick identification and correction of fPM control device malfunctions. PM CPMS have a distinct advantage over PM CEMS because operators do not have to contend with extensive and expensive QA testing that increases emissions to create the correlation curve.[72] For these reasons, EPA should retain the option to use PM CPMS.

8. EPA should evaluate the labor hour associated with PM monitoring

Stack testing is an important tool used to determine a facility's compliance with emission limits or capture or control efficiencies established pursuant to the CAA. An APPA member evaluated the labor hours required to complete PM CPMS testing under the current MATS Rule compared to EPA's proposal. When MATS was first enacted, public power utilities had to quickly choose a compliance strategy. Among the choices were the use of a PM monitor as a full CEMS or the use of a PM monitor as a CPMS. These choices were made based on costs, staff expertise, and source-specific operational conditions. Given the limited number of environmental staff, PM CPMS and quarterly stack testing were determined to require far fewer labor hours to perform testing. For comparison, the tables below provide labor hours associated with testing activities for CPMS and PM CEMS. A four-year frequency is provided to show variability in manpower requirements for PM CEMS compared to consistent resource allocation for PM CPMS annual tests. A CPMS is a much less burdensome and reliable alternative. The Table below shows that PM CEMS would require 792 labor hours as compared to 130 labor hours.

*Figure 5 PM CPMS versus PM CEMS Estimated Labor Hours for Winyah and Cross Generating Stations*

| Station | Unit | Compliance Option | Year 1 | Year 2 | Year 3 | Year 4 | Total Hrs/Unit | 4 year Total |
|---|---|---|---|---|---|---|---|---|
| Winyah | 1 | PM CPMS | 5 | 5 | 5 | 5 | 20 | 130 |
| | 2 | PM CPMS | 5 | 5 | 5 | 5 | 20 | |
| | 3 | PM CPMS | 5 | 5 | 5 | 5 | 20 | |
| | 4 | PM CPMS | 5 | 5 | 5 | 5 | 20 | |
| Cross | 1 | QST/LEE | 5 | | | 5 | 10 | |
| | 2 | PM CPMS | 5 | 5 | 5 | 5 | 20 | |
| | 3 | QST/LEE | 5 | | | 5 | 10 | |
| | 4 | QST/LEE | 5 | | | 5 | 10 | |
| Both Stations | (8 units) | PM CEMS | 45 | 9 | 9 | 36 | 99 | 792 |

[72] RTP Particulate Monitoring Technical Report at Section 5.

### B. PM CEMS monitoring changes are problematic.

EPA discusses and solicits comment on technical areas regarding how PM CEMS instrumentation functions, costs, calibration methods, capabilities and accuracy.

1. PM Test Run Minimum Sample Value.

APPA opposes the Proposed Rule's suggested revisions to increase PM test runs, which would result in costly, lengthy tests that have negative consequences on operating equipment and the environment. The proposal would increase the minimum sample volume requirement for performing MATS-modified[73] EPA Reference Method 5 from one (1) dry standard cubic meter (dscm) to four (4) dscm.

EPA claims this revision will reduce the "random error" associated with the measurement to less than 15%. However, EPA's supporting documentation[74] c departs from previous statements by EPA on the appropriate MDL to apply for Reference Method 5.[75]

APPA recommends using 1 mg as the MDL for a MATS-modified EPA Reference Method 5 test run and an associated PQL/LOQ of 3 mg. These values will demonstrate reliable results at the current, proposed fPM emission limits. At the lowest proposed limit of 0.006 lb/mmBtu, a one-hour MATS-Modified EPA Reference Method 5 test run operated at a nominal sample rate of 0.75 dry standard cubic foot per minute (dscfm) would yield a sample volume of ~45 dscf (i.e., 1.27 dscm). At a "desired target concentration" of 3.4 mg/dscm, a one-hour test duration should yield a sample mass of ~4.3 mg. That expected sample mass is ~44% higher than the PQL/LOQ of 3 mg. Source operators and their qualified stack testers should retain flexibility to obtain the necessary sample mass (in excess of 3 mg) in whatever sample volume and run time is appropriate based on the anticipated particulate loading level being tested.

Based on calculations outlined in the RTP PM Monitoring Report, doubling the sample volume in LEE stack test data had no significant impact on the overall variability in the fPM emission rate measurement. EPA's proposal to quadrupling the sample volume is not expected to have any significant impact on the overall variability in the fPM emission rate measurement at the proposed fPM emission limit value. Increasing the minimum sample volume increases the duration of each required test. The cost, burden, and environmental impact of each test is likewise increased as a result of establishing an unreasonable minimum sample volume.[76]

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[73] Sample probe and sample filter temperatures maintained at 320 °F (±25 °F).
[74] *See* EPA-HQ-OAR-2018-0794-5786
[75] For further discussion, *seeRTP Particulate Monitoring Technical Report* at Section 3; *see also* presentation of Steffan Johnson, Leader of EPA's Measurement Technology Group, "Bringing Minimum Detection Levels into Focus."
[76] RTP Particulate Monitoring Technical Report at Table 6.

2. PM CEMS QA/QC Requirements.

As presented *supra*, PM CEMS QA/QC requirements introduce unnecessary impacts to the environment due to the artificial PM loading requirements of Performance Specification 11 (PS-11). For example, an EGU with an ESP and wet FGD may need to intentionally turn off multiple fields of its ESP to achieve an increase in particulate matter needed for the test. If the unit has a wet FGD, slurry injection may need to be reduced to negate any filterable PM reduction in the wet FGD. Others may increase slurry injection to allow more scrubber carry-over. An EGU with a baghouse may need to intentionally bypass the baghouse to achieve an increase in particulate matter for the test. These conditions do not reflect normal conditions that are expected to occur for the extended duration during normal operation but are necessary to conduct testing.

Based on prior experience certifying PM CEMS, multiple source testing attempts failed to satisfy the PS-11 requirements and created compliance concerns by detuning particulate control systems to obtain elevated PM conditions. We observe that EPA should not propose changes in the MATS Rule that will extend the duration of these abnormal operation conditions. Not only is there a downstream impact on other process equipment, but more importantly, increased emissions during testing may have an environmental impact. In addition, meeting the requirements of PS-11 which apply to both new correlations and adjusted correlations following unsuccessful RCAs will be even more difficult with a lower fPM limit, as the tolerance interval criteria depend on the applicable emission limit.

As an alternative to correlation curve methodology, EPRI has developed a Quantitative Aerosol Generator (QAG) to allow direct PM CEMS calibration. The QAG has exhibited potential on selected sources using the current MATS filterable particulate matter limit of 0.030 lb/mmBtu. The QAG is not currently an approved test method for correlating PM CEMS and has not been subject to ongoing evaluation since 2019. The limited number of qualified professionals able to conduct QAG calibration services and lack of “Other Test Method” approval renders the QAG not commercially available for new PM CEMS installations.[77]

In summary, EPA should be mindful of PM CEMS requirements that increase the time for which sources must detune control devices. As the fPM limitation drops lower, the frequency of QA/QC tests and detune conditions will rise. APPA advocates for minimizing intentional emissions increases as much as possible. In Section D, we offer suggestions to reduce the time in which control devices must be detuned.

[77] RTP Particulate Monitoring Technical Report at Section 3.2.

### C. PM CEMS installation times should be extended.

The Proposed Rule provides three years after the promulgation date of the final RTR rule to install PM CEMS.[78] As such, many units would need to install CEMS by approximately 2027.[79] EPA should provide more timing flexibility for installation of PM CEMS. APPA advocates for an additional year and the ability to apply for an extension based on economic hardship or inadequate time to perform the project. Those EGUs that plan to retire by 2032 should have the opportunity to seek a waiver from installation altogether and continue quarterly stack testing during the remaining life of the unit.

Three years is an insufficient time frame to expect sources to install PM CEMS for several reasons. The Proposed Rule would require the majority of the coal-fired fleet to install PM CEMS during a compressed time period, although RTP reports that only four vendors are currently providing PM CEMS to EGUs. Compounding the problem, many new PM CEMS installations will be on wet stacks, but only three models are currently available for use in a wet stack environment.[80]

CEMS vendors will also be engaged in other replacement activities in addition to the new installations. For example, Sick, the vendor with the largest market-share of PM CEMS, will no longer service or support its FWE 200 model by September 1, 2027. EGUs with Sick FWE 200 models in service will be replaced over the next four years. Replacement of existing PM CEMS concurrently with installation of a large number of new PM CEMS will strain equipment vendors, integrators, and stack testers' ability to meet the demand of this proposal.[81]

As we previously noted, this proposal would increase the number and duration of PM CEMS tests for all MATS affected units due to unsuccessful RAAs and RCAs and the proposed MDL revision. Stack testers are already struggling to keep up with demand and retention of qualified staff. Consequently, stack testers may not be able to accommodate the increased testing burden contemplated by this proposal. The increased demand and limited availability of qualified stack testers will make it impossible to adjust due to unavoidable schedule changes, such as unplanned outages. EGU owners may not be able to find adequate testing personnel during normal operating periods and may experience more frequent "force run" situations. EPA should closely examine available CEMS vendors and qualified stack testing personnel for resource adequacy as a significant factor before implementing these significant changes.

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[78] *See* Red Line Strike Out Rule Text MATS RTR Document, https://www.epa.gov/system/files/documents/2023-04/MATS_63SubpartUUUUU_RTR_Proposal_RLSO_RTI_DRAFT_v1.pdf (MATS RTR Redline) at Proposed 40 CFR § 63.9984(h)(2).

[79] This is a calculated date based on estimates of the release of the Final Rule.

[80] In the preamble, EPA state that the manufacturing of beta gauge PM CEMS has ceased, but that is not accurate based on email correspondence with MSI, the Beta Guard 3.0 manufacturer.

[81] RTP Particulate Monitoring Technical Report at Section 2.

### D. Conclusions regarding PM CEMS

APPA strongly supports EPA retaining stack testing for compliance with the fPM limitation due to concerns our members and technical experts have raised regarding PM CEMS accuracy, additional fPM emissions, cost, and timing concerns. Stack testing is a long-accepted method of compliance that should be an option.

Should EPA reject these bases, APPA provides the following suggestions that would reduce the annual audit cost burden on our members:

1. EPA should modify the MATS Appendix C requirements to state that an RCA is only required if an RRA is unsuccessful. RCAs should not be required based elapsed time (i.e., 12 calendar quarters).
2. EPA should minimize the frequency and duration of test runs conducted at increased particulate loading
   .
3. EPA should modify the MATS Appendix C requirements to allow use of "QA operating quarters" and "Grace Periods" consistent with 40 CFR Part 75 as incorporated into MATS Appendix A and Appendix B but omitted from MATS Appendix C.[82]

## VII. EPA's Projections of the Compliance Impacts of the Proposed Rule are in error.

APPA provides comments on Integrated Planning Model (IPM) reference case entitled "Post-IRA 2022 Reference Case" (Post-IRA IPM) used in this Proposed Rule. Our comments also extend to EPA's use of the reference case in other rulemakings. In this proposal, EPA seeks comment on how the IRA and other market and policy developments should inform the Agency's determination. While we generally agree that EPA may make projections to assess compliance impacts, those projections must be reasonable and premised on a firm foundation.

The Post-IRA IPM makes projections based on a number of tax credit provisions of the Inflation Reduction Act of 2022 (IRA), which address application of Carbon Capture and Storage (CCS) and other carbon mitigation options. These include: (i) New Clean Electricity Production Tax Credit (45Y); (ii) New Clean Electricity Investment Credit (48E); Manufacturing Production Credit (45X); CCS Credit (45Q); Nuclear Production Credit (45U); and Production of Clean Hydrogen (45V). EPA assumes that these IRA provisions will substantially change the generation mix of the nationwide power sector by 2030. The Post-IRA 2022 Reference Case includes compliance with EPA's suite of power sector rules.[83]

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[82] RTP Particulate Monitoring Technical Report at Section 3.1.

[83] In addition to the IRA, the Post-IRA 2022 Reference Case takes into account compliance with the following: (i) Revised Cross-State Air Pollution Rule (CSAPR) Update Rule; (ii) Standards of Performance for Greenhouse Gas Emissions from New, Modified and Reconstructed Stationary Sources:

APPA has significant reservations about the accuracy of EPA's assumptions that these new tax credits will have sweeping impacts on the power sector – particularly in the short-time frame of only 7 years for generation to be retired and replacement generation to be built. EPA's model fundamentally assumes that the IRA and other power sector rules will cause retirement decisions and replacement capacity to be built – which is uncertain in itself – and then forecasts that these changes can feasibly occur by 2030. Many variables would need to fall into place to achieve this outcome.

Although the IRA presents our members with helpful opportunities, APPA cautions EPA against getting too far ahead. The IRA has not been in place for even a year. Implementation efforts have just begun. EPA should not rely on the IRA in its projections in a rulemaking until implementation has further matured. It is premature to change baseline assumptions or justify the costs of the MATS RTR based on speculation about the impacts of the IRA. How IRA funds will be awarded, to whom, by when, and for what purpose are all current unknowns. On a programmatic level, the IRA simply has not yet matured to the point where it should be the basis of a regulatory cost-benefit analysis at this time.

For public power utilities, rural electric cooperatives, and other tax-exempt entities to make use of IRA's refundable direct pay tax credit regime, these entities must meet domestic content requirements, unless the project qualifies for certain waivers. As a result, implementation of these requirements and waivers will ultimately drive fundamental decisions about asset ownership and even the basic economics of a facility, not simply the credit amounts for which the project might otherwise qualify.

The mechanics and implementation of the IRA are complicated and under development. On April 4, 2023, the Internal Revenue Service (IRS) and Treasury released draft proposed domestic content rules for qualified energy projects under the IRA (Notice 2023-29).[84] Notice 2023-29 contains requirements that appear to be quite challenging to implement. No waivers to these requirements have been released at all.

For these reasons, it is evident, even early in the deployment process, that availing IRA money for energy transition projects is not straightforward and possibly not attainable. Key questions exist, such as whether public power ownership of qualifying facilities meets domestic content requirements. Draft rules such as Notice 2023-29 call into question whether requirements can reasonably or economically be met. There has been no indication of potential waivers for requirements for public power entities. Further, the timing to finalize these processes is completely unknown. Yet, EPA's

Electric Utility Generating Units; (iii) MATS Rule which was finalized in 2011; (iv) Various current and existing state regulations; (v) Current and existing RPS and Current Energy Standards; (vi) Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART); (vii) Platform reflects California AB 32 and RGGI; and (viii) Good Neighbor Federal Implementation Plan. Three non-air federal rules affecting EGUs are included: (i) Cooling Water Intakes 316(b) Rule; (ii) Coal Combustion Residuals (CCR), as of July 29, 2020; and (iii) Effluent Limitation Guidelines (cost adders were applied starting in 2025).

[84] Treasury Notice 2023-29 at https://www.irs.gov/pub/irs-drop/n-23-29.pdf

proposal speculates about the IRA's effects and timing of implementation of IRA on the industry and public power. The Act is not the lone solution to the Administration's climate goals, nor should it be optimistically treated as such in the cost estimates in this Rule and others.

The Proposed Rule's compliance impacts analysis is based on the Post-IRA IPM. That reference case is used to predict the post-Proposed Rule total EGU generating capacity, generating mix by fuel, and coal retirements. Assumptions and certain data used in the Post-IRA IPM are unrealistic and must be corrected.

The Post-IRA IPM's flaws are significant enough to result in a different rule outcome. EPA may take some liberties in its technical analysis, but there is a limit. EPA has some latitude to conduct its models and technical analysis without perfection, and EPA can even extrapolate results when data is missing. Yet, the Post-IRA IPM contains technical errors that, if corrected, are likely to result in a different rulemaking outcome.

EPA did not act reasonably[85] in relying on the Post-IRA IPM and other projections based on EPA's suite of power sector rules. The Technical Report identifies the major issues in the model. APPA summarizes the most significant findings below, which are described in more detail in the Technical Report:

- The Post-IRA 2022 Reference Case 2028 and 2030 Baselines are incorrect. The projections that EPA makes contain errors as to retirement assumptions, CCS retrofits, and coal to gas conversations. Our Technical Report discusses these flaws in more detail.
- EPA retired 55 coal-fired units that will be subject to the Proposed Rule in 2028 and assumed 27 units will retrofit with CCS by 2030.[86]

APPA urges EPA to adjust its model to: (1) Apply the correct retirement assumptions resulting from the Proposed Rule and correct other flaws in the model; (2) Eliminate reliance on the IRA or, at a minimum, use more conservative assumptions as to the IRA's impacts on the power sector; (3) Employ realistic expectations of power sector grid needs to maintain reliability; (4) Refrain from assuming renewable energy replacement generation has the same dispatch role as retiring coal assets; and (5) Correct errors we define as "mischaracterizations" of specific units.

**VIII. Conclusion.**

Thank you for your consideration of these comments. The Association looks forward to working with the Agency concerning this rulemaking. Should you have any questions regarding these comments, please contact Ms. Carolyn Slaughter (202-467-2900) or CSlaughter@publicpower.org.

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[85] EPA must act "reasonably" and not "flawlessly." *NRDC*, 529 F.3d at 1086.
[86] *Id.* at Section 8.2.

# APPENDIX A

# Technical Comments on
# National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology

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June 19, 2023

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## 1. Summary of Flaws in EPA's Approach

The following is a summary of flaws in EPA's analysis, further described in detail in this report.

Particulate Matter (PM) Database

EPA's database of PM emissions is inadequate. EPA attempts to capture typical PM emissions by acquiring samples from 3 years – 2017, 2019, and 2021. For the vast majority of the units – 80% - EPA uses only 2 of the potentially available 12 quarters (in those 3 years; up to 20 quarters from 2017 to 2021) of data to construct the PM database. Further, of these limited samples. EPA cites the lowest to reflect a target PM emissions rate. EPA cites the use of the "99$^{th}$ percentile" PM rate in lieu of the average compensates for variability; but this approach accounts for variability within a single ("the lowest") quarter. It fails to account for long-term variability, which is affected by changes in fuel and process conditions, among others.

Lack of Design and Compliance Margin

EPA recognizes the need for margin in both design and operation (for compliance) of environmental control equipment, but ignores this concept in developing this proposed rule. The need for design margin is recognized in a 2012 OAQPS memo[1] addressing the initial developments of this very same rule, while margin for operation is considered in evaluating CEMS calibration[2] for this proposed rule. Neither design nor operating margin is considered in setting target PM standards, resulting in underestimation of number of units affected and total costs to deploy control technology. For some owners of fabric filter-equipped units, the revised rate of 0.010 lbs/MBtu eliminates any operating margin.

Inadequate Cost for ESP Rebuild

Of three categories of ESP upgrades considered by EPA, the cost for the most extensive – a complete rebuild to add collecting plate area – is inadequate. Four such major ESP rebuild projects have been implemented for which costs are reported in the public domain – and not acknowledged by EPA. Incorporating these results elevates the range of cost from EPA's estimate of $75-100/kW to $57-213/kW. Consequently, the "average" cost for this action used in the cost per ton ($/ton) evaluation increases from $87/kW to $133/kW.

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[1] Hutson, N., National Emission Standards for Hazardous Air Pollutants (NESHAP) Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired Electric Utility Steam Generating Units, Memo to Docket No. EPA-HQ-OAR—2009-0234, November 16, 2012. Hereafter Hutson 2012.

[2] Parker, B., PM CEMS Random Error Contribution by Emission Limit, Memo to Docket ID No. EPA-HQ-OAR-2018-0794, March 22, 2023. Hereafter Parker 2023.

Inadequate $/ton Removal Cost

As a consequence of under-predicting capital required for ESP "rebuild," and not recognizing the need for a design and operating margin, EPA under-predicts the number of units requiring retrofit and incurred cost. As a result, in contrast to the annual cost of $169.7 M projected by the Industry Study described in this report, EPA estimates a range from $77.3 to $93.2 M. Further, the Industry Study estimates the cost per ton ($/ton) of fPM to be $67,400, 50% more than the maximum cost estimated by EPA - $44,900 /ton.

Faulty Lignite Hg Rate Revision

EPA's proposal to lower the Hg emission rate for lignite-fired units to 1.2 lbs/TBtu is based on improper interpretation of Hg emissions data – both in terms of the mean rate and variability. EPA's projection that 85 and 90% Hg removal would be required for the proposed rate is incorrect, with up to 95% Hg removal required for some units – a level of Hg reduction not feasible in commercial systems. In addition to the variability of Hg content in lignite, EPA ignores the deleterious role of flue gas $SO_3$ in lignite-fired units, which compromises sorbent performance and effectiveness – even though this latter barrier is recognized and cited by EPA's contractor for the IPM model.[3]

Faults in IPM Modeling

IPM creates a flawed Baseline scenario that does not adequately measure the impacts of the proposed rule. Most notably, IPM err in the number of coal units that would be retired in both 2028 and 2030; as a consequence, EPA underestimates the number of units subject to the proposed rule. Also, IPM unrealistically retrofitted 27 coal units with carbon capture and storage (CCS) in 2030. Consequently, IPM modeling results of the Baseline likely understate the compliance impacts of the proposed rule.

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[3] IPM Model – Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology, Prepared by Sargent & Lundy, Project 12847-002, March 2013.

## 2. Introduction

The Environmental Protection Agency (EPA) is proposing to amend the National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Coal- and Oil-fired Electric Utility Steam Generating Units (EGUs), otherwise known as the Mercury and Air Toxics Standards (MATS). The specific emissions limits being revised address the filterable particulate matter (fPM) standard (which is the surrogate standard for non-mercury (Hg) metal HAPs); the Hg standard for lignite-fired units; fPM measurement methods for compliance; and the definition of startup. This report provides a review and evaluation of EPA's approach to selecting the revised fPM standard, the capital and annual costs for achieving the proposed revised standard, and the cost per ton ($/ton) to control non-Hg metal HAPs; and a critique of EPA's basis for proposing an Hg limit of 1.2 lbs/TBtu for lignite-fired units. This document also provides information supporting EPA's decision to retain the present Hg limit for bituminous and subbituminous coal.

The proposal to lower fPM and Hg limits is premised on EPA's interpretation of data related to the cost and capabilities of PM and Hg emission control technologies. EPA reports to have conducted realistic assessments of PM and Hg emissions and control technology capabilities in support of their analysis. EPA's assumptions are reported in the MATS_RTR_Proposal_Technology Review Memo[4] where EPA describes the PM database they developed, the cost and control capabilities of upgrades to electrostatic precipitators (ESPs) and fabric filters, and their understanding of the key factors that affect Hg emissions in bituminous, subbituminous, and lignite coal - and how the latter are alike or differ.

Many of EPA's assumptions are contrary to data in their possession or strategies previously adopted by EPA, but not considered. EGUs have been reporting fPM compliance data to EPA since MATS became applicable to them – i.e., for the vast majority of EGU, April 2015 or April 2016 for units that obtained a one-year extension. However, EPA's effort to "mine" fPM emissions data from prior years provides a sparse, inadequate database that does not reflect operating duty nor account for inevitable variability; further EPA misinterprets this information. No design or operating margins are considered in setting fPM (the same is true for lignite Hg emission rates). The cost to upgrade ESPs to meet the proposed limits is inadequate for the most significant modification EPA envisions – the complete ESP Rebuild. The cost to deploy enhanced operating and maintenance (O&M) actions on existing fabric filers is inadequate. Regarding revised Hg limits for lignite coal, EPA does not recognize the differences in lignite versus Powder River Basin (PRB) subbituminous coal that effect Hg control. EPA draws an incorrect analogy between PRB and lignite, improperly assuming the Hg removal by carbon sorbent observed with PRB can be replicated on lignite.

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[4] Benish, S. et. al., 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, Memo to Docket ID No. EPA-HQ-OAR-2018-0794. January 2023. Hereafter RTR Tech Memo.

The remaining sections of this report detail the findings summarized in Section 1, and are as follows:

- Section 3 describes EPA's approach to assembling their fPM database, and the flaws and weaknesses in their approach.
- Section 4 evaluates the fPM rates assigned by the database for the EPA analysis.
- Section 5 evaluates EPA's cost bases for the proposed fPM revised standard, and compares these to the realistic assumptions used in the Industry Study described in the paper.
- Section 6 addresses EPA's proposal to lower Hg from lignite-fired units to 1.2 lbs/TBtu, delineating the shortcomings in EPA's approach and assumptions.
- Section 7 provides historical data for Hg emission from non-low rank fuels, showcasing the inherent variability in the 30-day rolling average.
- Section 8 reviews the IPM modeling analysis conducted by EPA to support this rule.
- Appendix B presents examples of PM emission timelines for a limited number of units[5] that show how EPA's sparse database does not capture the authentic "PM signature" of the units.

[5] We reviewed data for a limited number of units because the comment period was very short and did not allow adequate time to undertake a more thorough review. EPA has all the data and in our opinion should have conducted such an analysis for every unit at issue.

# 3. Description of EPA Reference PM Database

Section 3 describes the PM database assembled by EPA which serves as the basis for the proposed NESHAP rule. Section 3 first describes the coal fleet inventory reflected, and then identifies shortcomings of this database concerning (a) selection of the sample year and quarter, (b) number of samples considered, and (c) data analysis.

## 3.1 Coal Fleet Inventory

EPA projects that a total of 275 generating units will be operating at the compliance date of January 1, 2028, representing a reduction from the present (2023) operating inventory of approximately 450 units. EPA identified the 275 units based on their estimate of unit retirements and units planning to switch to natural gas by the compliance date. EPA accounted for these assets not as individual units, but in terms of the number of reporting monitors to the Clean Air Markets Division. As 27 units employ common stack reporting, the data presented by EPA in the draft rule and RTR Tech Memo consider 248 discrete data points that reflect the 275 units. This analysis will adopt the same reporting methodology.

EPA's selection of 275 units contains 22 units that have publicly disclosed plans to retire or switch to natural gas by the compliance date of January 1, 2028. For the purposes of this analysis, these units are retained in the database so the results can be more readily compared.

Figure 3-1 depicts the installed inventory projected by EPA, presented according to the suite of control technology. The first two bars (from the left) report units equipped with ESPs as the primary PM control device in the following configurations: a total of 54,116 MW for an ESP followed by a wet FGD; and a total of 16,346 MW with an ESP only. The next 3 bars describe the total inventory equipped with a fabric filter in the following three configurations: 12,194 MW with the fabric filer as the sole device; 20,206 MW with a fabric filter followed by a wet FGD, and 19,995 MW where the fabric filter is preceded by a dry FGD process. Consequently, the bulk of the inventory (70,462 MW) will employ an ESP as part of the control scheme, with 52,395 MW employing a fabric filter for PM. Given the role of wet FGD in PM emissions – in most cases such devices will reduce PM by approximately 50% - more than half (74,322 MW) employ wet FGD as the last control step.

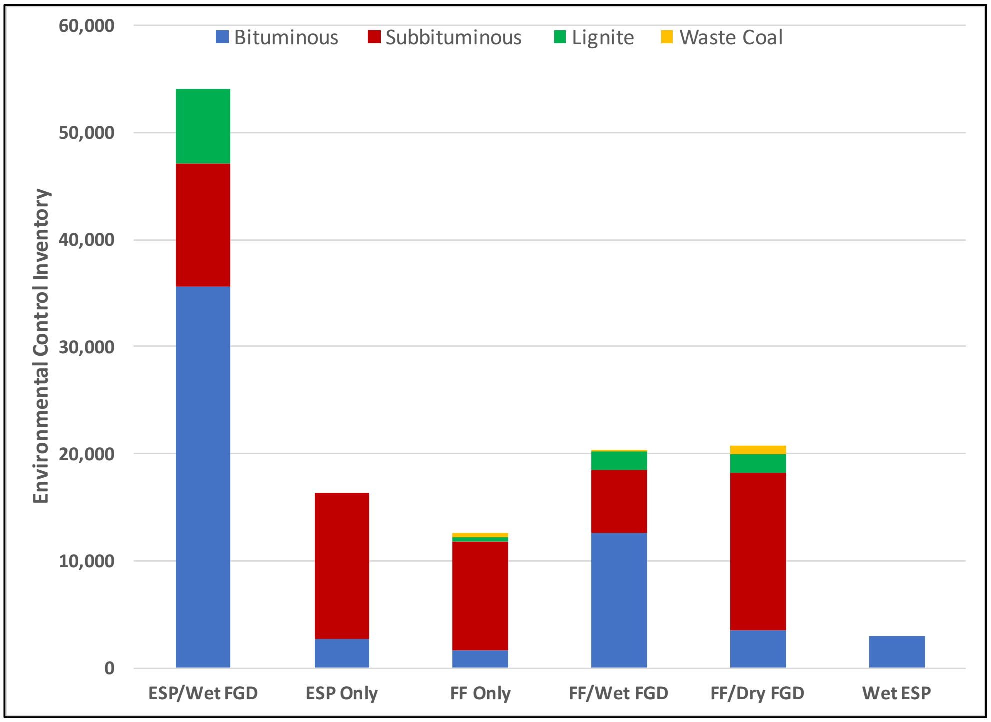


Figure 3-1. Inventory of EPA-Project 2028 Fleet by Control Technology Suite

## 3.2 Database Characteristics

Several characteristics of EPA's database severely compromise the quality of the analysis. These are the (a) selection of sampling year and quarter and (b) number of samples used.

### 3.2.1 Selection of Sample Year and Quarter

EPA does not describe the rationale for the limited data selected. The selection of three reference years (2017, 2019, and 2021) from at least 5-6 years of data readily available to EPA, and the sampling periods within each year (typically the 1st or the 3rd quarter even though all quarters are generally available) are not discussed. EPA extracts data from the year 2021 using a different approach from the years 2019 and 2017 without explanation. EPA states for 2021 that 2 quarters of data are utilized (always the 1st and the 3rd). For 2019, EPA reports utilizing data from "quarters three and occasionally four" while for 2017 EPA reports data acquired from "variable quarters."[6]

The rationale for the irregular selection of quarters is not stated. For 2021, the first and third quarters are selected with no technical basis. For 2019, the selection of quarters three and "occasionally" four does not replicate the time periods selected for 2021. For 2017, there is no description of the quarters or selection criteria.

EPA ignores a rich field of data that could support a much more robust and reasonable analysis.

[6] RTR Tech Memo, page 2.

### 3.2.2 Number of Samples

The number of discrete data points in EPA's Reference Database – defined by the number of operating quarters – is extremely limited. EPA's description of the sampling approach[7] is as follows:

*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 emission 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).*

Figure 3-2 shows most monitor locations — 193 of the 245 — are characterized by only 2 quarters of data, which is inadequate compared to the 16 or 20 EPA has access to.  The distribution of quarters selected by EPA according to either CEMS or stack test measurement for all 245 locations is shown. The second largest category is 33 units characterized by 4 quarters.

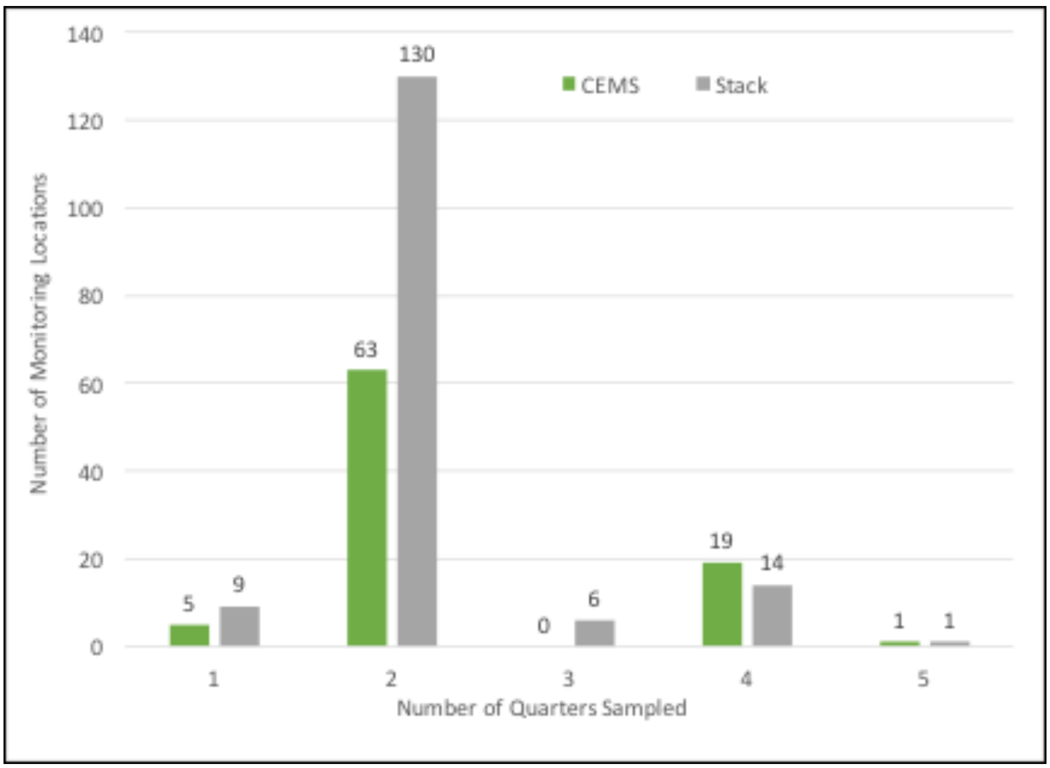


Figure 3-2. Numbers of Quarters Sampled by EPA for Use in PM Database

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[7] RTR Tech Memo, page 2.

Additional depictions of the data (not shown) reveal that only nine units are described by data in 2017, and 187 units by data from 2019. Only 41 units are described by data in 2021; the lack of data in 2021 was intentional as EPA considered this year only if data from 2017 or 2019 showed the unit exceeding the 0.010 lbs/MBtu proposed limit.[8] In other words, EPA looked at 2021 only when it was trying to find an emission rate less than 0.010 lbs/MBtu for a unit.

#### 3.2.3 PM Data Selection and Analysis

EPA does not explain the methodology chosen to reflect each quarters' emission rate, using at least two methods, depending on the year. EPA followed a four-step process to construct its database to select the "base rate" for each unit. The process is described as follows:

<u>Step 1: Quarter Selection</u>. EPA looked at 2-4 (usually 2) quarters for each unit. EPA states: "Quarterly data from 2017 (variable quarters) and 2019 (quarters three and occasionally four) were first reviewed …. 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)."[9]

As noted previously, EPA considered Q1 and Q3 2021 data solely to find a PM rate lower than 0.010 lb/MMBtu, and further explained: "The quarterly 2021 data summarizes recent emissions and also reflect the time of year where electricity demand is typically higher and when EGUs tend to operate more and with higher loads."[10]

<u>Step 2. Select Single Quarter</u>. From the candidate quarters identified in Step 1, EPA selected a single value, using criteria specific for each tests methodology:

- *PM CEMS*: for quarters in 2017 and 2019, EPA selected the 30-day average observed on the last day of the quarter; for quarters in 2021, EPA determined the average of the 30-day rolling averages observed in that quarter.
- *Stack Tests*: EPA took the average of the multiple (usually 3) test runs.

<u>Step 3. Select Lowest Quarter</u>. EPA selected the "lowest quarter" PM rate from the quarters selected in Step 2.

<u>Step 4. Determine PM of 99th Percentile.</u> For this lowest quarter per Step 3, EPA calculated the statistical percentile values as observed over the entire quarter. The methodology varied on whether PM CEMS or stack test data was provided. For PM CEMS, the percentiles were calculated for all 30-day rolling averages in the quarter. For stack tests, the percentiles were calculated for the typically 3 test runs.

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[8] Personal communication: Sarah Benish to Liz Williams, April 28, 2023. "*Data for 2021 was mined only for the EGUs that showed 2017 or 2019 fPM data above 1.0E-02 lb/MMBtu. We did not mine 2021 PM data for EGUs not expected to be impacted by the proposed fPM limit.*"
[9] RTR Memo, page 2.
[10] Ibid.

The results are reported in Appendix B of the Technology Review Memo. The 99th percentile rate was chosen as the "base rate," supposedly to account for variability within the "lowest quarter."

EPA does not describe why data selected was restricted to the years 2017, 2019, and 2021. EPA does not explain why 2021 data was limited to the 1st and 3rd quarters, 2019 data was limited to the 3rd and occasionally the 4th quarter, while 2017 data from variable quarters could be utilized.

Of concern is the limited subset of data used for this analysis – Figure 3-2 showed that for 80% of the units the lowest is selected from only two samples. EPA states "By using the lowest quarter's 99th percentile as the baseline, the analyses account for actions individual EGUs have already taken to improve and maintain PM emissions."[11] EPA states employing the PM rate at the 99th percentile –reflecting approximately the highest data within that quarter – remedies any bias.[12]

There is no basis for this statement. EPA is assuming that because a unit emitted fPM during a single quarter at a particular level, the lowest such level must necessarily reflect "actions individual EGUs have already taken to improve and maintain PM emissions," and therefore each EGU must be able to replicate that rate in every quarter going forward, indefinitely. Also, EPA ignores the unavoidable variability in emission rates: the "actions individual EGUs have already taken to improve and maintain PM emissions" are not the only factor that determines fPM emissions rate. The factors that affect fPM rates are numerous and include but are not limited to the following: coal quality (e.g., chemical composition and ash content) which varies within a single mine; variation in temperature within an ESP; content of $SO_3$ and trace constituents that determine ash electrical resistivity; physical conditions (spacing) of collecting plates and emitting electrodes; effectiveness of the rapping "hammers" that dislodge collected ash from the collecting plates; and physical properties of the collected ash layer that define ash re-entrainment. Further, boiler operation will influence ESP performance, most notably unit duty (i.e., relatively stable operating level for a "baseload" unit versus more load changes for an intermediate unit or a unit operating in peaking mode), operating level, and load "ramp" rate. Achieving the "least emission" rate observed during a quarter that EPA selected is not necessarily feasible at other times and under other conditions.

### 3.2.4 Example Cases

Figure 3-3 presents an example that demonstrate the shortcomings of EPA's approach. Figure 3-3 presents PM data from Coronado Generating Station Units 1 and 2 reflecting all operating quarters from 2017 through 2021. Both the average PM rate and the 99th percentile from each quarter are presented for 20 quarters of operation over the 4-year period. Figure 3-3 also identifies the two samples EPA selected from 2017 Q3 and 2019 Q3 as representative of low fPM rate, with the latter as the "least" – and the 99th-percentile reporting 0.0086 lbs/MBtu. Figure 3-3 shows EPA's two samples do not capture the full character of Coronado operating duty (with the red dotted line denoting the PM rate selected as representative of the units'

[11] RTR Tech Memo, page 4.
[12] Ibid.

capabilities to control PM). These quarters as selected by EPA are far from representative of unit operations or capabilities: among 20 quarters for which data are available, the units' 90$^{th}$ percentile fPM rates exceed the 0.0086 lbs/MBtu rate EPA selected for 16 quarters. Ten out of 20 quarters showed 90$^{th}$ percentile fPM rates exceeded the proposed standard of 0.010 lb/MBtu.

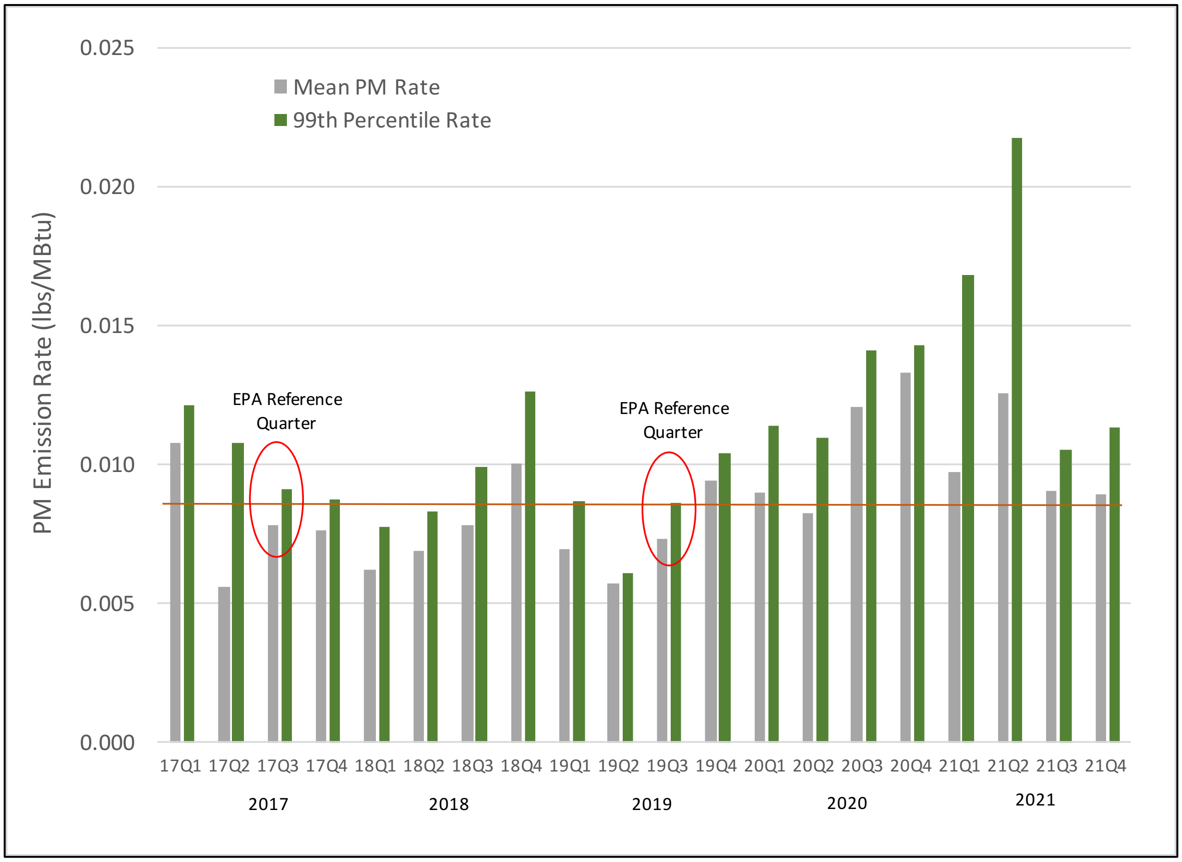

Figure 3-3. Coronado Generating Station: 20 Operating Quarters

Coronado Units 1/2 show how selecting the least PM rate of any quarter, and adopting the 99$^{th}$ percentile PM rate within that quarter, does not capture the variability in fPM emission rates, which are affected by the variability of coal and operating conditions, among others.  These examples demonstrate that EPA used best-case fPM data from both compliance measures (continuous monitor and performance test data).

Additional examples are presented in the Appendix B to this report.

## 3.3 Conclusions

- EPA's database is sparse and does not fully capture operating duty. Of the 275 units and approximately 250 monitoring locations, the vast majority – 80% - are characterized by only two samples.

- Selecting the lowest quarter  - "one" of what in most cases are "two" samples - fails to capture the operating profile of the unit, and presents a serious deficiency in representing operations. EPA's approach of considering the 99$^{th}$ percentile within a quarter is inadequate to assess variability, particularly that induced by fuel composition, as such fuel changes are observed over a characteristic time of years and not several months.

- The use of statistical means within one quarter does not capture the multi-month variances in coal composition, seasonal load, and process conditions that are not constrained to 3-month events.

- An improved, robust database would allow observing variation between– as opposed to within – operating quarters, to better reflect variations and uncertainties in operating duty and fuel supply.

## 4. Coal Fleet PM Emissions Characteristics

Section 4 characterizes the coal-fired fleet selected to represent the PM emissions

The emission control technologies on the 275 units projected by EPA to be operating in 2028 present a variety of approaches to lower fPM emission limits – with implications for upgrades and actions that would be required to meet a revised standard for fPM. This subsection presents the distribution of control technology by ability to operate below the revised PM limits for the units in EPA's database. By necessity, this analysis uses EPA's database (both for a discussion of expected or achievable fPM emission rates and the units projected to operate in 2028 and later), and such use does not represent an endorsement or acceptance of EPA's approach. As discussed above, EPA's analysis of expected/achievable fPM emission rates is inadequate. And as discussed later in this report, EPA's selection of units that would continue to operate after 2028 is flawed: it contains multiple errors; and EPA's post-IRA IPM analysis is inaccurate.

Figure 4-1 is used to present our analysis.

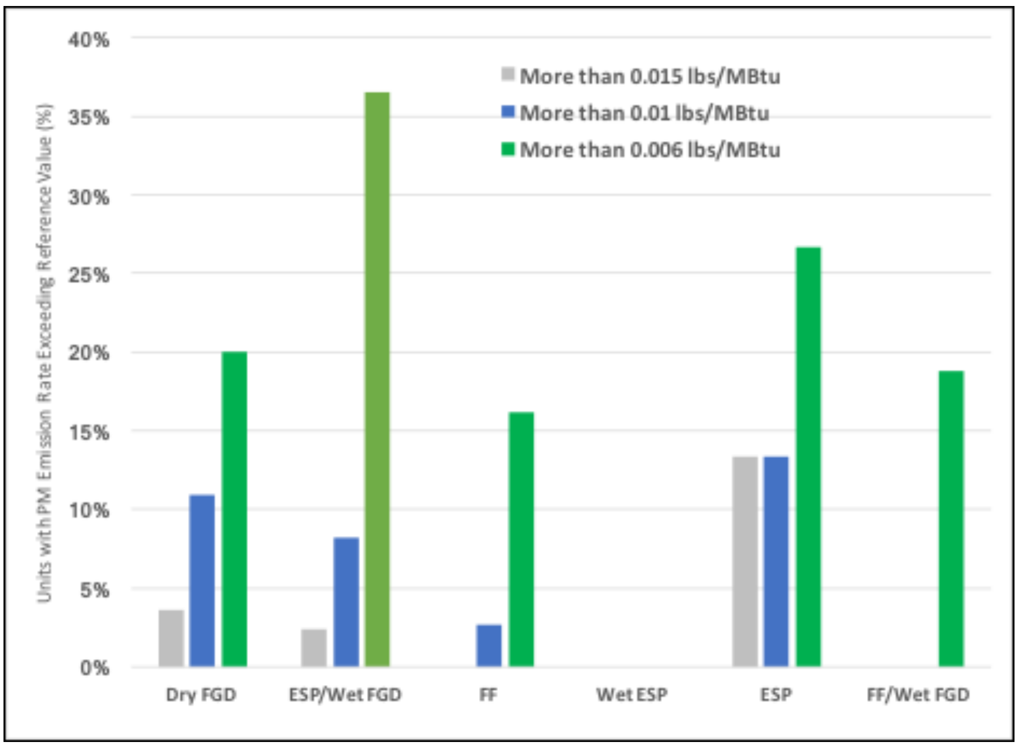


Figure 4-1. Fraction of Units Exceeding Three PM Rates: By Control Technology

Figure 4-1 presents for five control technology configurations the percentage of units that emit (according to EPA's chosen "base rate") above the following PM emission limits: 0.015 lbs/MBtu, 0.010 lbs/MBtu, and 0.006 lbs/MBtu. The control technologies are (a) dry FGD with a fabric filter, (b) ESP followed by a wet FGD, (c) fabric filter alone (employing low sulfur coal or multi-unit station-averaging to meet an $SO_2$ limit), (d) wet ESP as the last control device, (e) ESP alone (employing low sulfur coal or multi-unit station-averaging to meet an $SO_2$ limit), and (f) fabric filter followed by a wet FGD.

In Figure 4-1, the proportion of units in the inventory that exceed the contemplated fPM rate is proportional to the height of the bar; a higher bar implies a greater fraction of units in the inventory exceed the contemplated fPM rate. Thus:

#### 4.1.1 PM Rate of 0.015 lbs/MBtu

Units in three categories exceed this highest contemplated rate – those with an ESP alone, a dry FGD followed by a fabric filter, and an ESP followed by a wet FGD. The latter category of ESP/wet FGD benefits in that actions within the absorber tower – although not designed to removed fPM – can under some conditions remove fPM. Data describing PM removal via wet FGD is sparse but suggests 50% removal can be observed.

#### 4.1.2 PM Rate of 0.010 lbs/MBtu

The number of units in each of the three preceding categories exceeding this rate increases – there is no change for the category of ESP-alone, but the number of units exceeding this rate more than triple for dry FGD/fabric filter and ESP/wet FGD. No units with fabric filter/wet FGD or a wet ESP emit at greater than this rate.

#### 4.1.3 PM Rate of 0.006 lbs/MBtu

The number of units exceeding a rate of 0.006 lbs/MBtu increases with this most stringent contemplated rate. More than 1/3 of the units with ESP/wet FGD and ¼ of ESP- only cannot meet this rate, with fabric filters either operating with dry FGD (20%) or alone (16%) not achieving this target. Almost 20% of those with fabric filter/wet FGD units emit greater than this value.

In conclusion, within six major categories of control technology, units equipped with fabric filters achieve the lowest PM rates. Units with ESPs – either operating alone or with a wet FGD- represent the highest fraction of their population that exceed the strictest contemplated rate. Units with fabric filters – operating alone, or as part of a wet or dry FGD arrangement – are among the lowest exceeding the strictest contemplated PM rate. As noted previously, this analysis used EPA's database (as reflected in Appendix B of the RTR Tech Memo) out of necessity, and such use does not represent an endorsement or acceptance of EPA's approach.

# 5. CRITIQUE OF COST-EFFECTIVENESS CALCULATIONS

Section 5 addresses the cost effectiveness ($/ton basis) estimated to reduce the PM emission rate to EPA's proposed limit of 0.010 lbs/MBtu, and the alternative limit of 0.006 lbs/MBtu. EPA has conducted this calculation with inputs based on analysis by Sargent & Lundy (S&L)[13] and Andover Technology Partners (ATP).[14] EPA's results are presented in both Table 3 of the proposed rule and in Table 7 of the RTR Tech Memo.

This section reviews EPA's calculation methodology, critiques inputs of the EPA Study, and presents results of an Industry Study that utilizes realistic costs. Results from EPA's evaluation and the Industry Study addressing the 0.010 lbs/MBtu and 0.006 lbs/MBtu PM rates are compared.

## 5.1 EPA Evaluation

### 5.1.1 EPA Study Inputs

The EPA study used both the PM database described in Section 3 and cost and technology assumptions derived by the above-mentioned S&L and ATP references. As noted in Section 2, EPA's sparsely-populated database is inadequate from which to base a revised PM rate that represents a significant reduction in PM emissions but is achievable in long-term duty.

The analyses by S&L and ATP provide capital cost for three categories of ESP upgrades, improvements to fabric filter operating and maintenance (O&M) and associated costs, capital requirement for fabric filter retrofit and associated O&M cost. Most of the analysis is premised on the costs and PM removal performance of ESP upgrades as defined by S&L. It should be noted S&L did not provide specific projects with publicly available data as the basis of their assumptions.

The most significant shortcoming of EPA's assumptions is low capital estimates for the most significant ESP upgrade - the "ESP Rebuild" scenario. In contrast to the generalizations of the S&L memo, Table 5-2 reports publicly documented costs incurred for "ESP Rebuild." Equally significant, EPA ignores the inherent variability of fPM and FGD process equipment by not utilizing a design or operating margin in selecting the value of fPM rates that would require operator action. This is counter to EPA's prior acknowledgement of the use of margin in the initial rulemaking for MATS[15] and recent observations as to CEMS calibration.[16] It is also contrary to basic operation goals: no source operates at the applicable standard; a compliance

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[13] PM Incremental Improvement Memo, Project 13527-002, Prepared by Sargent & Lundy, March 2023. Hereafter S&L PM Improvement Memo.

[14] Analysis of PM Emission Control Costs and Capabilities, Memo from Jim Staudt (Andover Technology Partners) to Erich Eschmann, March 22, 2023. Hereafter ATP 2023.

[15] Hutson 2012.

[16] Parker 2023.

margin is always necessary, at least to account for unavoidable variability of performance in the real world. By ignoring the need for margin, EPA's evaluation under-predicts the number of units that would be retrofit with new or upgraded control technology to meet the target rate.

These and other critiques of EPA's approach are discussed subsequently.

Shortcomings in EPA inputs compromise the results of their analysis. These shortcomings, as well as other observations, are summarized as follows:

ESP Upgrade. Three categories of ESP upgrade are proposed by EPA. The most significant shortcoming relates to the "ESP Rebuild" category in which - as described by S&L – additional plate area is added to the ESP. The addition of collecting surface area will require major changes to – or demolition and complete rebuilding of – the gas flow confinement that houses the existing collecting plates. Also, these process changes require specialized labor for fabrication and installation that may be limited in availability. The costs suggested by S&L (without citation of references) - $75-100/kW –are low when compared to publicly disclosed costs from similar projects.

Fabric Filter O&M. Fabric-filter-equipped units that emit greater than 0.010 lbs/MBtu are assumed to adopt enhanced O&M practices. These enhanced practices consist of (a) upgrading filter material to higher quality fabrics, such PTFE, and (b) increasing the replacement frequency so that filters are replaced on a 3-year basis. The cost premium for this action, based on analysis by ATP, does not consider the additional manpower costs for the more frequent replacement.

Fabric Filter Construction. EPA's range of capital cost for retrofit of fabric filter technology is consistent with industry experience.

Design/Compliance Margin. A premise of environmental control system design is accounting for variability due to many factors, including, for example, variations in fuel composition, operating load, and process conditions. Such variability is generally addressed by a design/compliance margin – selecting a target emission rate less than mandated by a standard. The concept of design/compliance margin is broadly applied in the industry, and was acknowledged in a 2012 EPA memo summarizing the range of margin adopted by various process suppliers, with a minimum cited as 20-30%.[17] EPA did not adopt a design/compliance or operating margin in selecting fPM emission rates for a revised fPM standard in this evaluation, despite the fact that elsewhere in the record of this proposal EPA acknowledges a typical "operational target" of 50% of the limit.[18] Because of its assumption of no design/compliance margin whatsoever, EPA presumes that units that report an operating fPM of 0.010 lbs/MBtu – based on EPA's sparse database - require no investment to meet the proposed standard of 0.010 lb/MBtu.

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[17] Hutson, N., National Emission Standards for Hazardous Air Pollutants (NESHAP) Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired Electric Utility Steam Generating Units, Memo to Docket No. EPA-HQ-OAR—2009-0234, November 16, 2012.

[18] Parker 2023.

Separate from the preceding issues, EPA did not disclose the capacity factors assumed in the analysis. The capacity factor can be inferred from the tons of PM removed as reported in Appendix B of the RTR Tech Memo; this requires acquiring heat input and net plant heat rate from AMPD and EIA data.

### 5.1.2 EPA Results

Table 5-1 presents results of EPA's evaluation.

Table 5-1. Summary of EPA Results

| **EPA Study** | | | | | |
|---|---|---|---|---|---|
| **Unit Affected** | Tons fPM Removed | Annual Cost ($M/y) | $/ton fPM (average) | Non-Hg metallic HAPS Removed (tons) | $/ton non-Hg metallic HAP ($000s) |
| **Target: 0.010 lbs/MBtu** | | | | | |
| **20** | 2,074 | 77.3-93.2 | 37,300-44,900 | 6.34 | 12,200-14,700 |
| **Target: 0.006 lbs/MBtu** | | | | | |
| **65** | 6,163 | 633 | 103 | 24.7 | 25,600 |

Proposed Limit: 0.010 lbs/MBtu. EPA estimates 20 units in the entire inventory are required to retrofit some form of ESP upgrade. The number of units with existing fabric filters required to enhance O&M is not identified, nor is their cost. EPA estimates a range in annual cost to implement the ESP and fabric filter O&M enhancement of $77.3 to 93.2 M/yr, with the range determined by the range in cost and performance of each option as described by S&L.[19] This total annualized cost translates into an average fPM removal cost effectiveness of $37,300 - $44,900 per ton of fPM and $12.2M -$14.7 M per ton of total non-Hg metallic HAPs. These steps remove a total of 2,074 tons of fPM (6.34 tons of total non-Hg metallic HAPs) annually.

EPA did not consider in its analysis the potential impact of the capital cost of major controls construction or upgrades (i.e., ESP rebuilds for most of the 20 units; new Fabric Filters for the two Colstrip units) on the viability of the units at which such rebuilds would occur. Appendix Figure A-1 presents the capital required for each unit as designated by EPA for upgrade – requiring an investment likely prohibitive for continued operation.

Potential Limit: 0.006 lbs/MBtu. EPA estimates 65 units in the entire inventory are required to retrofit a fabric filter or deploy enhanced O&M to an existing fabric filter. EPA estimate an annual cost of $633 M/yr will be incurred, at an average cost effectiveness of $103,000 per ton

[19] S&L PM Improvement Memo.

of fPM and $25.6 M per ton of total non-Hg metallic HAPs. These steps remove a total of 6,163 tons of fPM (24.7 tons of total non-Hg metallic HAPs) annually.

## 5.2 Industry Study

The Industry Study alters several assumptions to reflect actual, documented cost data and the necessity of a design/compliance margin. Table 5-2 presents these results.

### 5.2.1 Revised Cost Inputs

The modified cost inputs necessary to reflect authentic conditions ESP upgrade and fabric filter operation are discussed as follows.

<u>ESP Upgrades.</u> The three categories of ESP upgrades are assessed as follows.

*Minor Upgrades (Low Cost).* Both the cost range and PM removal efficiency for this activity as estimated by S&L are adopted for this analysis. ESPs requiring Minor Upgrade are assigned a $17/kW cost to derive an average of 7.5% removal of fPM.

*Typical Upgrades (Average Cost).* Both the cost range and PM removal efficiency for this activity as estimated by S&L are adopted for this analysis. ESPs requiring Typical Upgrade are assigned a $55/kW cost to derive an average of 15% fPM removal.

*ESP Rebuild (High Cost).* The cost range for this activity as estimated by S&L does not reflect that reported publicly for four projects that represent the "ESP Rebuild" category. Two projects were completed at the AES Petersburg station – the complete renovation of the ESPs on Units 1 and 4[20] for which S&L provided engineering services. The cost for this work has been publicly reported in 2016-dollar basis. Two additional major ESP upgrades were implemented by Ameren at the Labadie station unit in 2014 – with costs publicly reported.[21]

Table 5-2 summarizes the cost incurred for the four major ESP retrofits, including costs in the year incurred and escalated (using the Chemical Engineering Process Cost Index)[22] to 2021. Table 5-1 shows a cost range of $57-209/kW, with 3 of the 4 units incurring a cost exceeding $100/kW. These costs significantly exceed EPA's maximum for this range.

[20] State of Indiana – Indian Public Utility Commission, Cause No. 44242, August 14, 2013. See Appendix, electronic page 50 of 51.
[21] Ameren Missouri Installs Clean Air Equipment at its Labadie Energy Center; https://ameren.mediaroom.com/news-releases?item=1351
[22] https://www.chemengonline.com/pci-home#:~:text=Since%20its%20introduction%20in%201963,from%20one%20period%20to%20another.

Table 5-2. ESP Rebuild Costs: Four Documented Cases

| Owner/Station | Unit | Basis Year | 2021 ($/kW) |
|---|---|---|---|
| **AES/Petersburg** | 1 | 2016 | 117 |
| **AES/Petersburg** | 4 | 2016 | 57 |
| **Ameren Labadie** | 1 | 2014 | 192 |
| **Ameren Labadie** | 2 | 2014 | 209 |

Consequently, the range of ESP rebuild costs is adjusted to $57-209/kW, and the mean value of $133/kW (2021 basis) selected to represent this category of upgrade.[23]

FF O&M. A fabric filter O&M cost was derived for existing units, based on the assumption by S&L that filter material will be upgraded, as well as the frequency of filter replacement. An increase in cost – reflected as fixed O&M – of $515,000 is estimated for a 500 MW unit. This cost premium is comprised of higher material cost of $425,000 to upgrade filter material to PTFE fabric and an additional $90,000 for installation labor. This cost premium as is assigned to existing units based on generating capacity, and using a conventional "6/10$^{th}$" power law.

The revised Industry Study costs are based on (a) gas flow volume treated, (b) surface area of filter required based on the unit design, (c) unit cost of filter (e.g. $ per ft$^2$ of cleaning surface), and (d) replacement rate of filter material. Gas flow treated for each unit was determined using the quantitative relationships derived by S&L for fabric filter cost evaluation developed for the IPM model.[24] Filter surface area was not defined for each unit as dependent on the specific air/cloth ratio; rather a fleet air/cloth ratio of 5 – a mean value between conventional and pulse-jet design concepts – is selected. The unit cost for fabric was selected (at $4.00/ft$^2$) per ATP analysis. Per S&L's IPM fabric filter costing procedure[25] and the EPA-sponsored review of filter material cost,[26] the increase in cost for enhanced O&M is derived. The cost to upgrade material, accelerate filter replacement (from 5 to 3 years) and supporting cages (from 9 to 6 year) intervals is estimated as $425K per year for a reference 500 MW unit.

Fabric Filter Capital Cost. EPA proposed a capital cost to retrofit a fabric filter as $150-$360/kW. The cost range offered by EPA is consistent with industry experience and is used in this study.

EPA did not share the incremental operating cost incurred by the retrofit fabric filters. The Industry Study adopted fixed and variable operating costs from the previously cited S&L fabric filter cost estimating procedure. For the assigned inputs, the S&L evaluation projects a fixed

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[23] Colstrip Units 3 and 4 are equipped with legacy FGD that combine removal of SO2 and PM in a wet venturi; there is not an ESP option to upgrade. Fabric filer retrofit is the only option; as Colstrip represents an atypical case the costs are reported in the category of Major ESP upgrade.

[24] IPM Model – Updates to Cost and Performance for APC Technologies: Particulate Control Cost Development Methodology, Project 13527-001, Sargent & Lundy, April 2017. Hereafter S&L Fabric Filter 2017.

[25] Ibid.

[26] ATP report.

O&M of $0.27/kW-yr and a variable operating cost of 0.48 $/MWh. The variable O&M cost is mostly comprised of filter replacement at the accelerated rate described, and auxiliary power.

Design/Compliance Margin. EPA in two public documents address – and apparently recognize – the need for design/compliance margin.[27] The use of design/compliance margin was acknowledged in a 2012 EPA memo summarizing the range adopted by various suppliers, citing a minimum of 20-30%.[28] For the proposed limit of 0.010 lbs/MBtu, the minimum of 20% is used as a design target for ESP upgrades. Thus, the Industry Study applied ESP upgrade and fabric filter O&M enhancements to attain 0.008 lbs/MBtu, in lieu of EPA's target of 0.010 lbs/MBtu. It should be noted this 20% margin is the least of those considered; if the highest operating margin of 50% suggested by EPA in the record of this rule was used the units requiring upgrade and the cost would have been even higher.

As noted by EPA, the sole reliable compliance means for a 0.006 lbs/MBtu PM rate is a fabric filter. Fabric filters historically exhibit low variability due to their inherent design; thus, the operating margin is slightly relaxed to 0.005 lbs/MBtu. Consequently, the Industry Study assumed ESP-equipped units emitting greater than 0.005 lbs/MBtu will retrofit a fabric filter to insure 0.006 lbs/MBtu is attained. Units with existing fabric filters operating at greater than 0.005 lbs/MBtu will adopt improved operation and maintenance, as previously described.

### 5.2.2 Cost Effectiveness Results

Revised costs from the Industry Study are projected for the proposed fPM limit of 0.010 lbs/MBtu, and the alternative rate of 0.006 lbs/MBtu. Table 5-4 presents these results.

Proposed Limit: 0.010 lbs/MBtu. Results derived in the Industry Study are reported for all three categories of ESP upgrade in Table 5-1. A total of 26 units are required to upgrade ESPs – 11 deploying *Minor*, 7 deploying *Typical*, and 8 deploying *Major* upgrades.[29] In addition, 11 units equipped with fabric filters are required to enhance O&M activities. The totality of these actions each year incur an operating cost of $169.7 M/yr, and remove 2,523 tons of PM.

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[27] Hutson, 2012 and Parker, 2023.

[28] Hutson, N., National Emission Standards for Hazardous Air Pollutants (NESHAP) Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired Electric Utility Steam Generating Units, Memo to Docket No. EPA-HQ-OAR—2009-0234, November 16, 2012. at 1 (discussing mercury); 2 (discussing PM).

[29] The two Colstrip units are equipped with an early generation FGD process which does not include an ESP, thus the concept of an ESP upgrade is irrelevant. Consistent with EPA's assumption, the Colstrip units are assumed to retrofit a fabric filter as the only option to meet a limit of 0.010 lbs/MBtu.

Table 5-3. Summary of Results: Industry Study

| Technology (Units Affected) | Annual Cost ($M/y) | Tons fPM Removed | $/ton fPM average | Non-Hg metallic HAPS Removed (tons) | $/ton non-Hg metallic HAP ($000s) |
|---|---|---|---|---|---|
| **Target: 0.010 lbs/MBtu** | | | | | |
| **ESP Minor (11)** | 20.9 | 100 | 209,340 | 0.31 | 67,470 |
| **ESP Typical (7)** | 34.7 | 282 | 122,926 | 0.86 | 40,216 |
| **ESP Major † (8)** | 113.6 | 1,665 | 68,228 | 5.1 | 21,662 |
| **FF O&M (11)** | 0.4 | 475 | 869 | 1.45 | 284 |
| **Total or Average** | 169.7 | 2,523 | 67.3 | 7.71 | 22,000 |
| **Target: 0.006 lbs/MBtu** | | | | | |
| **FF O&M (23)** | 1.23 | 652 | 1,887 | 2.61 | 617 |
| **FF Retrofit (52)** | 1,955.4 | 6,269 | 311,900 | 25.13 | 102,000 |
| **Total or Average** | 1,956.6 | 6,921 | 282,715 | 27.74 | 92,470 |

*† Includes 2 fabric filters retrofit to Colstrip Units 3 and 4. See footnote #23.*

The incurred cost per ton varies significantly by ESP upgrade category. For the ESP *Minor* upgrade, the average cost effectiveness is approximately $67,470,000 per ton of non-Hg metal HAP for 0.31 of tons removed ($209,340 per ton of fPM for 100 tons of fPM removed). The cost-effectiveness cost effectiveness for the ESP *Typical* upgrade average $40,216,000 per ton of non-Hg metal HAP for 0.86 tons removed ($122,956 tons of fPM for 282 tons of fPM removed). The *Major* upgrade removes the most non-Hg metal HAP – 5.1 tons – (1,665 tons of fPM) for an average cost effectiveness of $21,662,000 per ton of non-Hg metal HAP ($68,228 per ton of fPM). The most cost-effective control evaluated is enhanced fabric filter O&M, which removes 1.45 tons of non-Hg metal HAP at a cost-effectiveness of $284,230/ton (475 tons of fPM at a cost-effectiveness of $869/ton).

These actions cumulatively remove a total of 2,523 tons of PM for an average cost effectiveness of 22,000,000 per ton of non-Hg metal HAP ($67,262 per ton of fPM) removed, a 50% increase compared to the cost estimated by EPA.

Appendix Table A-1 reports the units to which the Industry Study assigned ESP upgrades, and defines the category of upgrade to meet the proposed fPM limit of 0.010 lbs/MBtu.

Possible Lower Limit: 0.006 lbs/MBtu. The Industry Study projects 52 ESP-equipped units would be required to retrofit a fabric filter, removing 25.13 tons of non-Hg metal HAP (6,269 tons of fPM) for an average cost effectiveness of $102,000,000 per ton of non-Hg metal HAP ($311,900 per ton of fPM). In addition, 23 existing units equipped with fabric filters would have to adopt enhanced O&M, removing an additional 2.61 tons of non-Hg metal HAP (652 tons of fPM) for an average of cost of $617,195/ton of non-Hg metal HAP ($1,887/ton of fPM). These actions cumulatively remove a total of 27.74 tons of non-Hg metal HAP (6,921 tons of fPM) for an average cost effectiveness of $92,470,000/ton non-Hg metal HAP ($282,715/ton of fPM) removed. These costs are a factor of almost three times that projected by EPA.

Appendix Table A-2 reports the units to which the Industry Study assigned fabric filter retrofits and enhancements of operating and maintenance procedures, to meet the alternative fPM limit of 0.006 lbs/MBtu.

## 5.3 Conclusions

- EPA's cost study is deficient in terms of the number of ESP-equipped units required to retrofit improvements, the capital cost assigned for the most significant *Major* ESP improvement, and estimates of $/ton cost-effectiveness incurred. EPA, by ignoring the need for a design and operating margin cited in at least two of their publications (Hutson, 2012 and Parker, 2023) under-predicts the number of units that would require retrofits.

- This study – using the minimum margin cited by EPA in previous publications – projects a much higher annual cost for capital equipment to meet the proposed 0.010 lbs/MBtu - $169.7 M versus EPA's maximum estimate of $93.3 M. To meet the alternative PM rate of 0.006 lbs/MBtu, this study projects 50% more units (87 versus 65) must be retrofit with fabric filters or implement enhanced O&M to an existing fabric filter, incurring an annual cost of $1.96 B versus EPA's estimate of 633 M/yr – a three-fold increase.

- As a consequence, this study predicts the cost effectiveness to meet 0.010 lbs/MBtu will average $22,000,000 per ton of non-Hg metal HAP removed ($67,262 per ton of fPM), a 50% premium to EPA's estimate of $12,200,000 - $14,700,000/ton of non-Hg metal HAP ($37,300 – $44,900/ton of fPM) removed. This study projects the cost to meet the alternative rate of 0.006 lbs/MBtu will average $92,470,000/ton non-Hg metal HAP ($282,715/ton fPM) removed, almost a factor of three higher than EPA's estimate of $103,000/ton.

# 6. Mercury Emissions: Lignite Coals

Section 6 addresses EPA's proposed action to reduce the limit for Hg for lignite-fired units to 1.2 lbs/TBtu. (the following Section 7 addresses EPA's proposal to retain the present emission limit of 1.2 lbs/TBtu for units firing bituminous and subbituminous coals (i.e., non-low rank fuels).) This section critiques EPA's basis for proposing the lignite Hg emission rate of 1.2 lbs/MBtu, while supporting the proposal to retain the existing rate for non-low rank coals.

EPA states the following in support of their proposal regarding lignite:

*".....ash from lignite and subbituminous coals tends to be more alkaline (relative to that from bituminous coal) due to the lower amounts of sulfur and halogen and the presence of a more alkaline and reactive (non-glassy) form of calcium in the ash. The natural alkalinity of the subbituminous and lignite fly ash can effectively neutralize the limited free halogen in the flue gas and prevent oxidation of the $Hg^0$.*

Both lignite and subbituminous coal do contain less sulfur than bituminous coal, but other major differences in composition exist that EPA does not recognize. These are Hg content and its variability, the sulfur content, and the alkalinity of inorganic matter. EPA's failure to recognize these differences manifests itself as (a) assuming activated carbon sorbent effectiveness observed on subbituminous coal (specifically PRB) extends to lignite, and (b) ignoring variability in Hg content, as well as the role of sulfur trioxide ($SO_3$), which compromises achieving 90%+ Hg removal as required to attain 1.2 lbs/TBtu.

Fuel properties are described separately for the North Dakota and Gulf Coast (Texas and Mississippi) lignite mines.

## 6.1 North Dakota Mines and Generating Units

Figures 6-1 to 6-4 present data provided by lignite suppliers from North Dakota mines that describe the variability for Hg and other constituents key to Hg removal. These figures present data as a "box and whisker" plot, which portrays the mean value, the 25$^{th}$ and 75$^{th}$ percentile of the observed data, and the near-minimum (5%) and near-maximum (95%) extremities. Figure 6-1 shows the variability of Hg and Figure 6-2 the variability of sulfur content. Figure 6-3 shows variability of fuel alkalinity compared to sulfur content – specifically, the ratio of calcium (Ca) and sodium (Na) to sulfur – i.e., the (Ca + Na)/S metric.

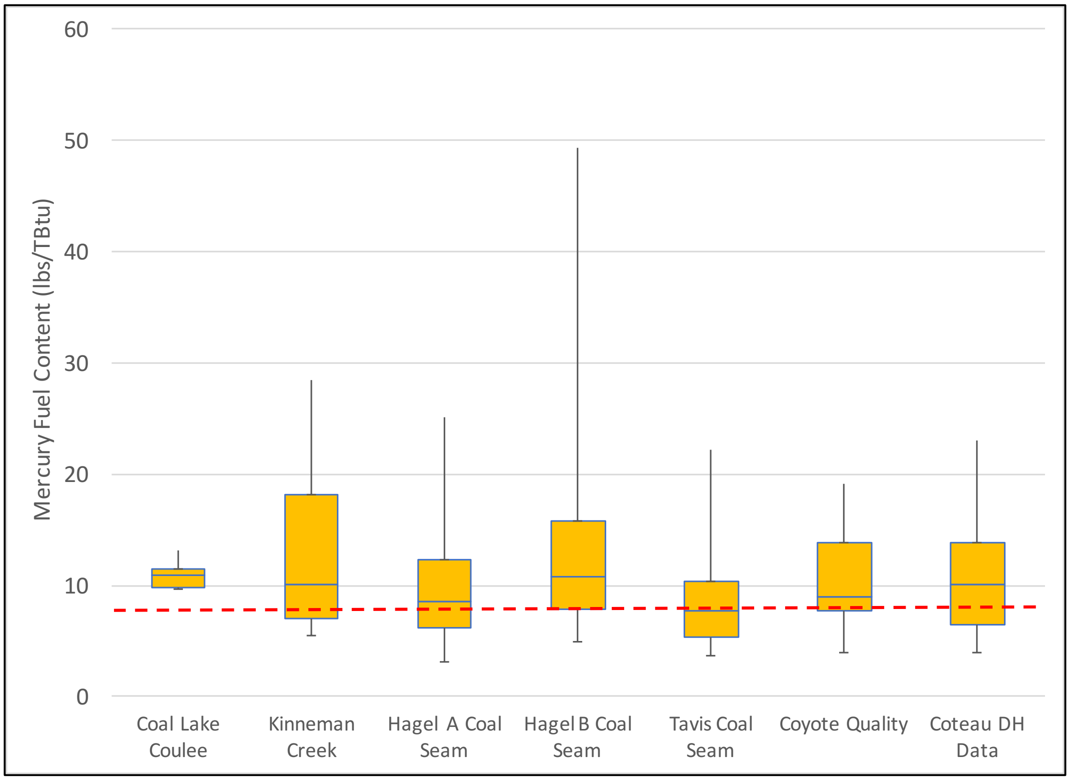


Figure 6-1. Mercury Content Variability for Eight North Dakota Lignite Mines

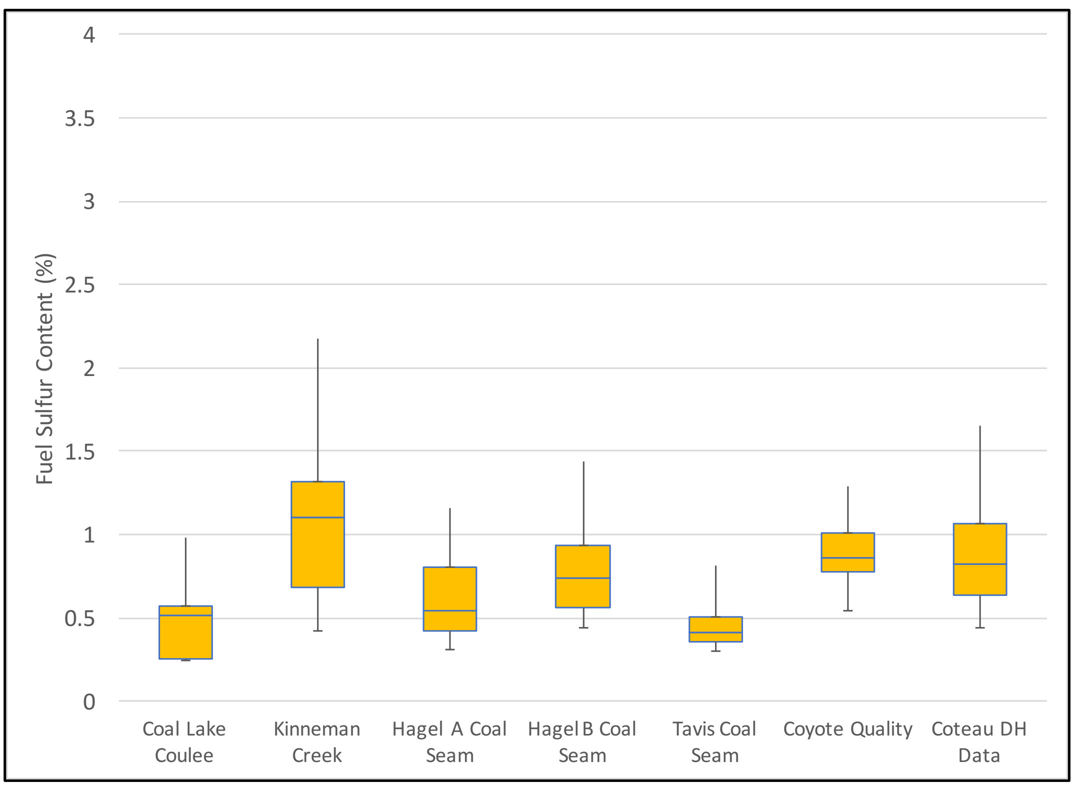


Figure 6-2. Fuel Sulfur Content Variability for Eight North Dakota Lignite Mines

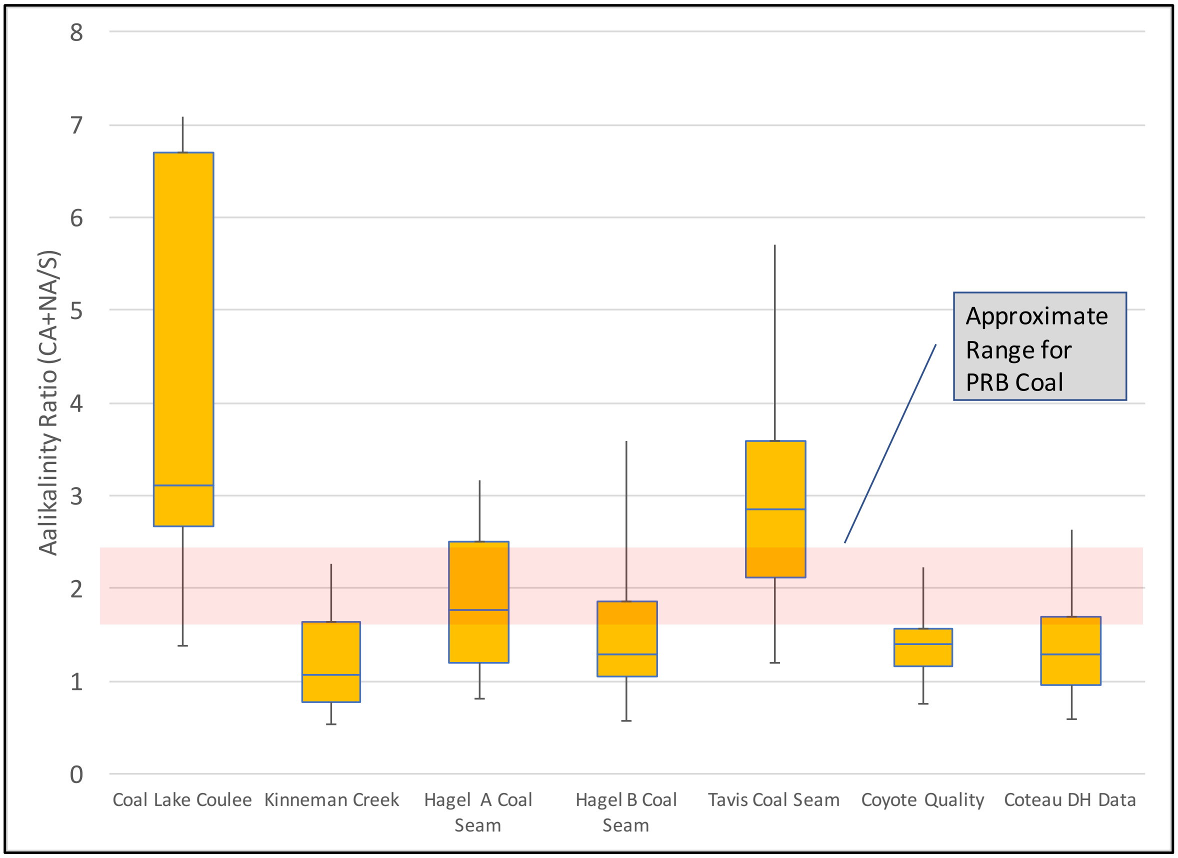


Figure 6-3. Fuel Alkalinity/Sulfur Ratio for Eight North Dakota Mines

Figure 6-1 compares the Hg content and variability to the fixed value of 7.7-7.8 lbs/TBu, assumed by EPA as representing North Dakota lignite, as summarized in Table 11 of the Tech Memo. Figure 6-1 shows – with the exception of the Tavis seam – all mean values of Hg content exceed EPA's assumed value that serves as the basis of EPA's evaluation. More notably, the 75$^{th}$ percentile value of Hg for each seam - slightly more than one standard deviation variance from the mean – in all cases significantly exceeds the value assumed by EPA.

Of note is that the variability of Hg depicted in Figure 6-1 is not necessarily observed only over extended periods of time – such as months or quarters – it can be witnessed over period of days or weeks. This is attributable to the sharp contrast in Hg content of seams that are geographically proximate and thus are mined within an abbreviated time period. Figure 6-4 presents a physical map showing the location of "boreholes" in a lignite field with imbedded text describing (in addition to the borehole code) the Hg content as ppm. The text boxes report this Hg content in terms of lbs/TBtu. These example boreholes – separated by typically 660 feet- and the factor of 3 to 6 variation of Hg content present a meaningful visualization of Hg variability in a lignite mine, and the consequences for the delivered fuel.

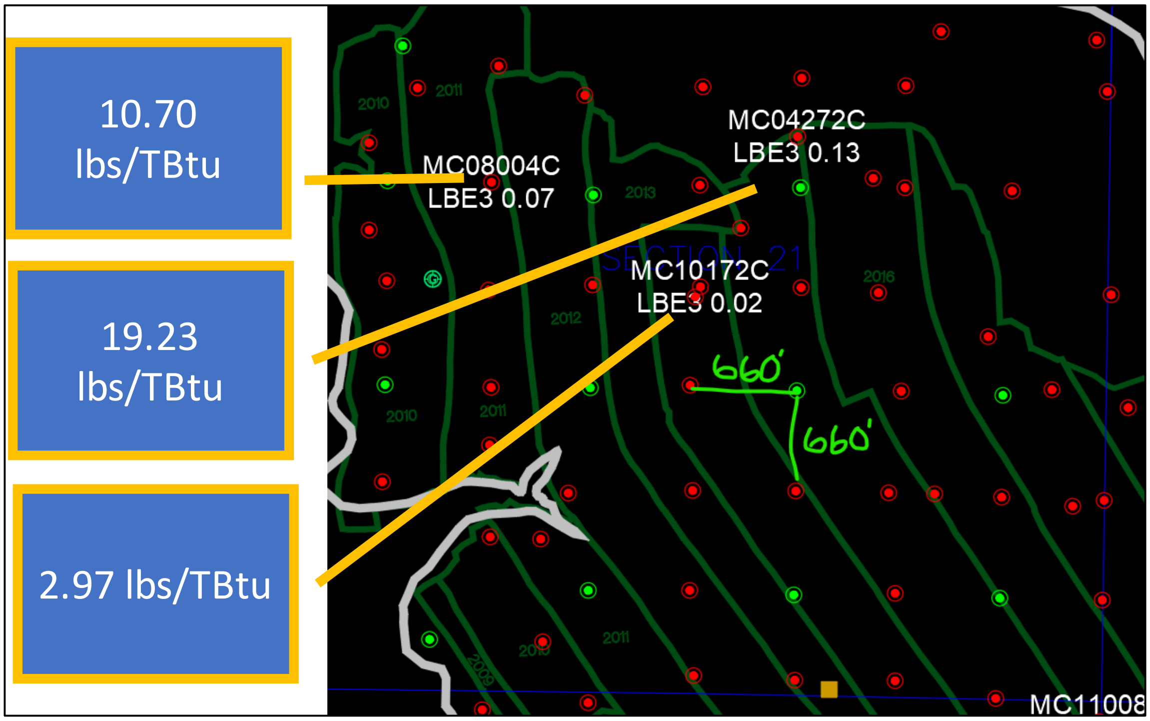


Figure 6-4. Spatial Variation of Hg in a Lignite Mine

Data from Figure 6-1 is summarized in Table 6-1 for units at four stations in North Dakota – Coal Creek, Antelope Valley, Coyote, and Leland Olds. Both Figures 6-1 and Table 6-1 show Hg variability exceed that assumed by EPA in their evaluation. Table 6-1 shows that achieving a 1.2 lbs/TBu requires an Hg removal rate of approximately 93-95% for unavoidable instances where coal Hg content is at the 95$^{th}$ percentile of observed value. The approximate 93-95% Hg removal requirements well exceed the 85% Hg removal based on the IPM-assigned Hg content.

Table 6-1. Hg Variability for Select North Dakota Reference Stations

| Station | Mine | Seams | IPM Designated Hg Rate (lbs/TBtu) | Inferred EIA 2021 Hg Rate (lbs/TBtu) | Hg Fuel Content at 95th Percentile (lbs/TBtu) | Hg Removal (%) for 1.2 lbs/TBtu at 95th Percentile |
|---|---|---|---|---|---|---|
| **Coal Creek** | Falkirk | UTAV, HGB1 and HGA1/HGA2 (Mostly Haga A seam) | 7.81 | 7.80 | 25.1 | 95.2 |
| **Antelope Valley** | Freedom | Freedom Mine Belauh Seam | 7.81 | 7.76 | 23.0 | 94.8 |
| **Coyote** | Coyote Creek | Coyote Upper Belauh | 7.81 | 7.79 | 19.2 | 93.8 |
| **Leland Olds** | Freedom | Kinneman Creek, Hagel A, Hagel B | 7.81 | 7.79 | 23.0 | 94.8 |

## 6.2 Texas Gulf Coast Mines and Generating Units

Figures 6-5 to 6-7 present data from Texas and Mississippi lignite mines describing the content and variability for Hg, sulfur, and the (Ca + Na)/S metric, as delivered to generating units in Texas. Analogous to the data cited for North Dakota, the "box and whisker" depiction represents the same metrics.

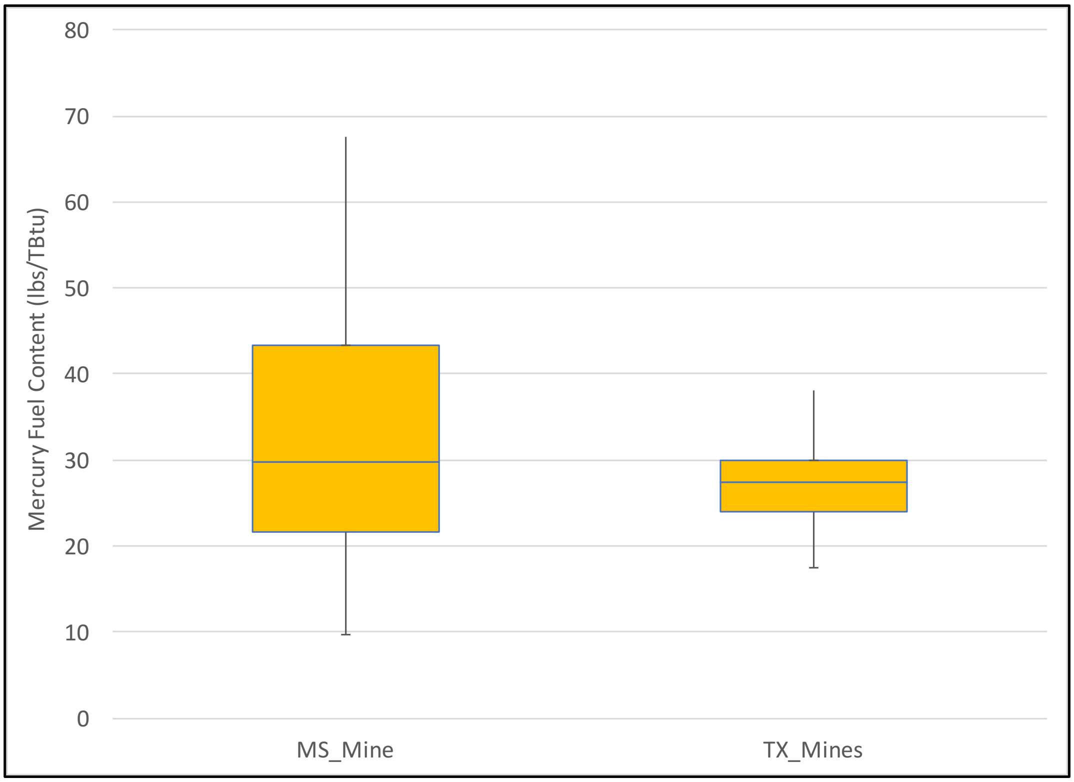


Figure 6-5. Mercury Variability for Two Gulf Coast Sources: Mississippi, Texas

Table 6-2 compares the Hg removal required to meet the proposed 1.2 lbs/TBtu rate considering the variability of Hg in Texas and Mississippi coals, instead of the IPM-assigned Hg coal content. For three Texas plants that fired 100% lignite – Major Oak Units 1 and 2, Oak Grove Units 1 and 2, and San Miguel – EPA assigned inlet Hg values from 12.44 to 14.88 lbs/TBtu, implying Hg removal of 90-92% to achieve 1.2 lbs/TBtu. However, based on the 95$^{th}$ percentile value of the Texas lignite Hg values from Figure 6-5, the required Hg removal would be 96-97%.

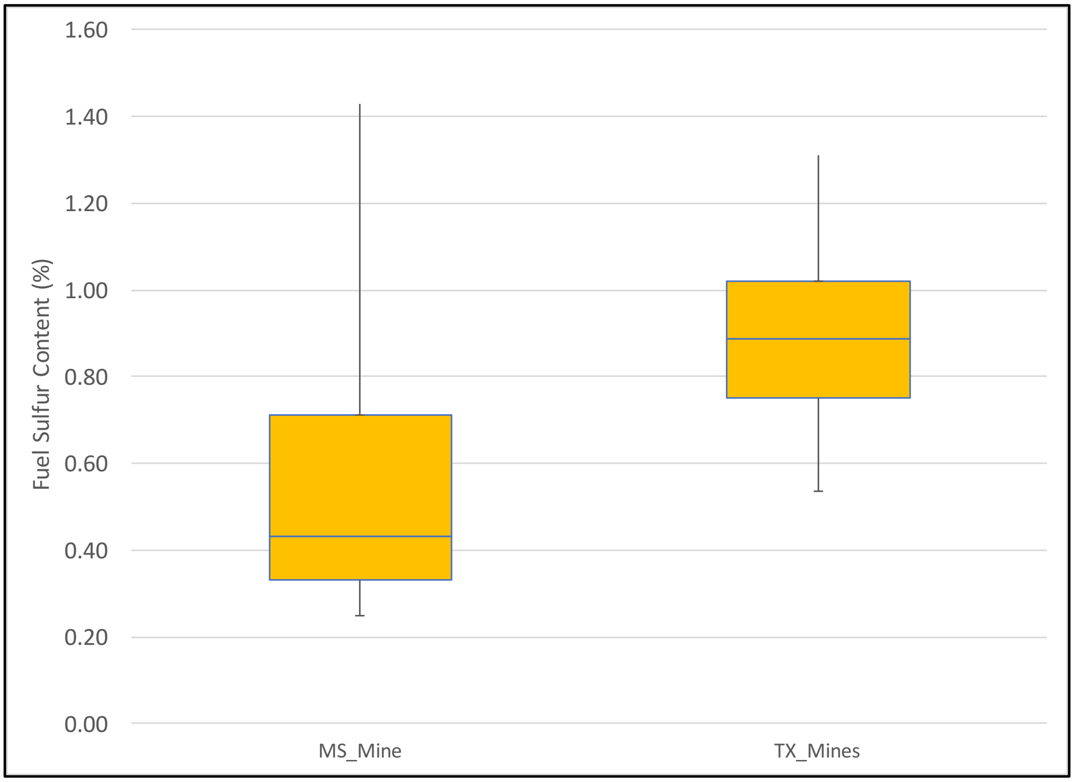


Figure 6-6. Sulfur Variability for Mississippi, Texas Lignite Mines19.1

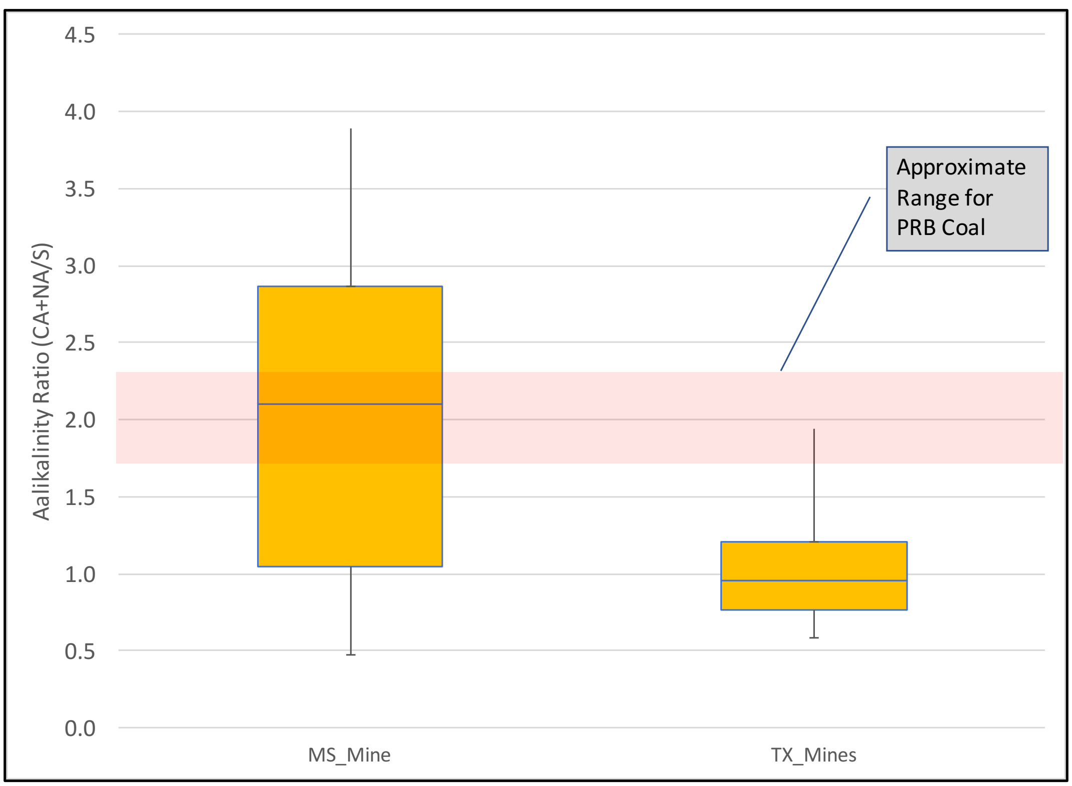


Figure 6-7. Fuel Alkalinity/Sulfur Ratio for Mississippi, Texas Lignite Mines

Table 6-2. Hg Variability for Select Texas Reference Stations

| Station | Mines | IPM Designated Hg Rate (lbs/TBtu) | Inferred EIA 2021 Hg Rate (lbs/TBtu) | Hg Fuel Content at 95th Percentile (lbs/TBtu) | Hg Removal (%) for 1.2 lbs/TBtu at 95th Percentile |
|---|---|---|---|---|---|
| **Major Oak 1,2** | Calvert | 14.65 | 14.62 | 38.12 | 96.9 |
| **Oak Grove 1, 2** | Kosse Strip | 14.88 | 14.6 | 38.12 | 96.9 |
| **Red Hills 1, 2** | Red Hills | 12.44 | 12.4 | 67.6 | 98.2 |
| **San Miguel** | San Miguel Lignite | 14.65 | 14.62 | 38.1 | 96.9 |

## 6.3 Role of Flue Gas SO3

EPA equates PRB and lignite coal in terms of constituents that affect Hg capture by carbon sorbent. Data from North Dakota and Gulf Coast mines, displayed in the previous Figures 6-1 to 6-7, show these fuels also contain higher sulfur content than PRB - by a factor or two or more. This relationship is verified by data acquired from EIA Form 960, as provided by power station owners. These fuel data, combined with inherent alkalinity, identifies the problematic role of flue gas $SO_3$ content.

### 6.3.1 EIA Hg-Sulfur Relationship

Figure 6-8 compares the seam-by-seam Hg and sulfur content from various power stations firing lignite coals, representing approximately 60 lignite mines and 40 PRB mines. Figure 6-8 shows, even excluding the outlier values of Hg (approximating 50 lbs/TBtu), lignite presents significantly greater variability in Hg and sulfur than PRB. Moreover, lignite coals have a much higher sulfur content than PRB and in many instances have twice the Hg content. The higher sulfur content of lignite equates to greater production rates of sulfur $SO_3$.

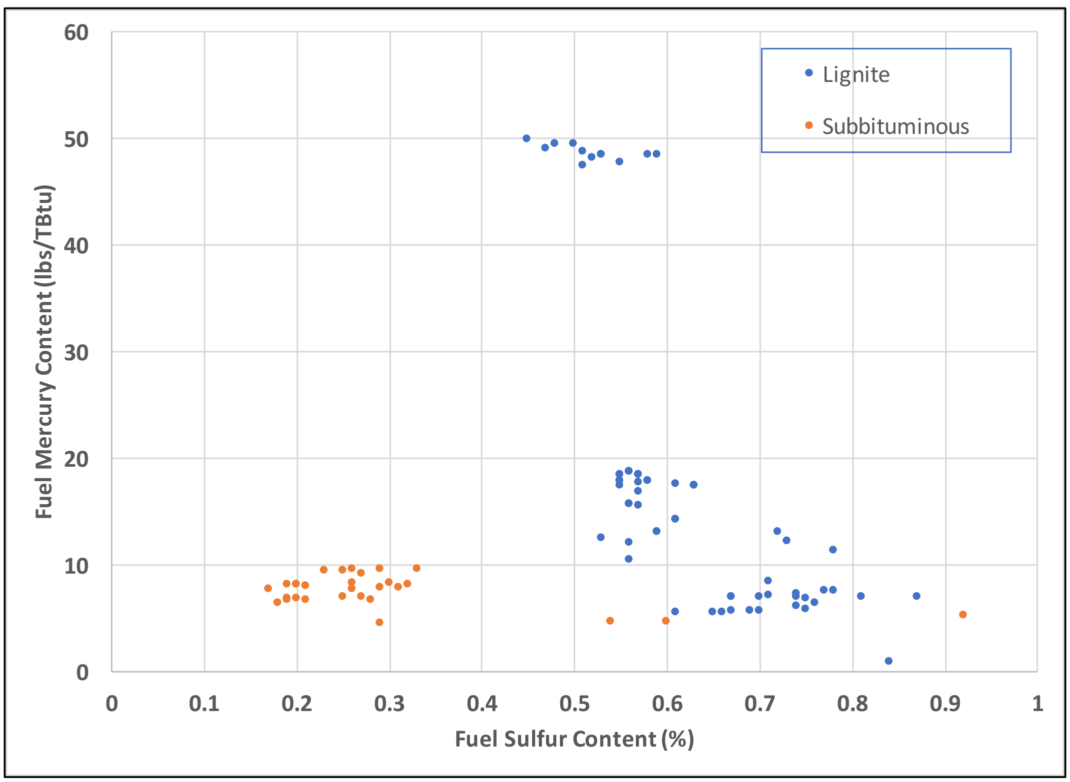


Figure 6-8. Lignite Hg and Sulfur Content Variability: 2021 EIA Submission

An additional factor is the amount of "inherent" alkalinity compared to sulfur – with higher value surpassing the $SO_3$ content in flue gas. As introduced previously, one metric of this feature is the ratio of Na and Ca to sulfur – on a mole basis.

Figures 6-3 and 6-7 show North Dakota and Gulf Coast lignite present a similar ratio of alkalinity to sulfur content as does PRB – approximating a value of 2. By this metric, lignite fuels in Figure 6-3 present similar means to "buffer" $SO_3$ as PRB. Notably, Texas lignite in Figure 6-7 is disadvantaged in this metric as the alkalinity to sulfur ratio is half that of PRB – reducing the buffering" effect of inherent ash.

Consequently, the higher sulfur content of lignite combined with equal or lower total alkali relative to sulfur allows measurable levels of $SO_3$ in lignite-generated flue gas, as evidenced by field measurements. EPA does not recognize this distinguishing difference, and states the following regarding lignite and subbituminous coal:[30]

*As mentioned earlier, EGUs firing subbituminous coal in 2021 emitted Hg at an average annual rate of 0.6 lb Hg/TBtu with measured values as low as 0.1 lb/TBtu. Clearly EGUs firing subbituminous coal have found control options to demonstrate compliance with the 1.2 lb/TBtu emission standard despite the challenges presented by the low natural halogen content of the coal and production of difficult-to-control elemental Hg vapor in the flue gas stream.*

This passage contains two major flaws – that the effectiveness of Hg removal techniques with PRB-generated flue gas can be replicated with lignite, and that average annual Hg emission rates are the metric for comparison. EPA fails to recognize that Hg removal in PRB is in the presence of very little (essentially unmeasurable) $SO_3$, and 30-day rolling averages exhibit variability not captured by the annual average.

### 6.3.2 $SO_3$: Inhibitor to Hg Removal

The ability of $SO_3$ to interfere with sorbent Hg removal is well-known.[31] Most notably, EPA's contractor for the technology assessments used in the IPM[32] – Sargent & Lundy –for EPA issued assessment on Hg control technology. This document states[33]

*With flue gas SO3 concentrations greater than 5 - 7 ppmv, the sorbent feed rate may be increased significantly to meet a high Hg removal and 90% or greater mercury removal may not be feasible in some cases. Based on commercial testing, capacity of activated carbon can be cut by as much as one half with an SO3 increase from just 5 ppmv to 10 ppmv.*

This passage from the S&L technology assessment – funded by EPA to support the IPM model - describes that Hg absorption capacity of carbon can be cut in half by an increase in $SO_3$ from 5 to 10 ppm. In addition, the presence of $SO_3$ asserts a secondary role in terms of gas temperature – units with measurable $SO_3$ are designed with higher gas temperature at the air heater exit – typically where sorbent is injected – to avoid corrosion. Special-purpose tests on a fabric filter

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[30] Tech Memo page 21

[31] Sjostrom 2019. See graphics 21-25

[32] Documentation for EPA's Power Sector Modeling Platform v6: Using the Integrated Planning Model, May 2018.

[33] IPM Model – Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology, Prepared by Sargent & Lundy, Project 12847-002, March 2013.

pilot plant showed an increase in gas temperature from 310ºF to 340ºF lowered sorbent Hg removal from 81% to 68%.[34] The role of $SO_3$ is not considered in assumed carbon injection rates for EPA's economic analysis in Tables 12 and 13 of the Tech Memo.

Publicly available field test data demonstrate the role of $SO_3$ on carbon sorbent effectiveness. Figure 6-9 presents results from a lignite-fired plant describing Hg removal across the ESP with sorbent injection.[35] This 900 MW unit is reported to fire a higher sulfur lignite in which more than 20 ppm of $SO_3$ in flue gas is observed preceding the air heater, subsequently decreasing to 10 ppm $SO_3$ existing the air heater.

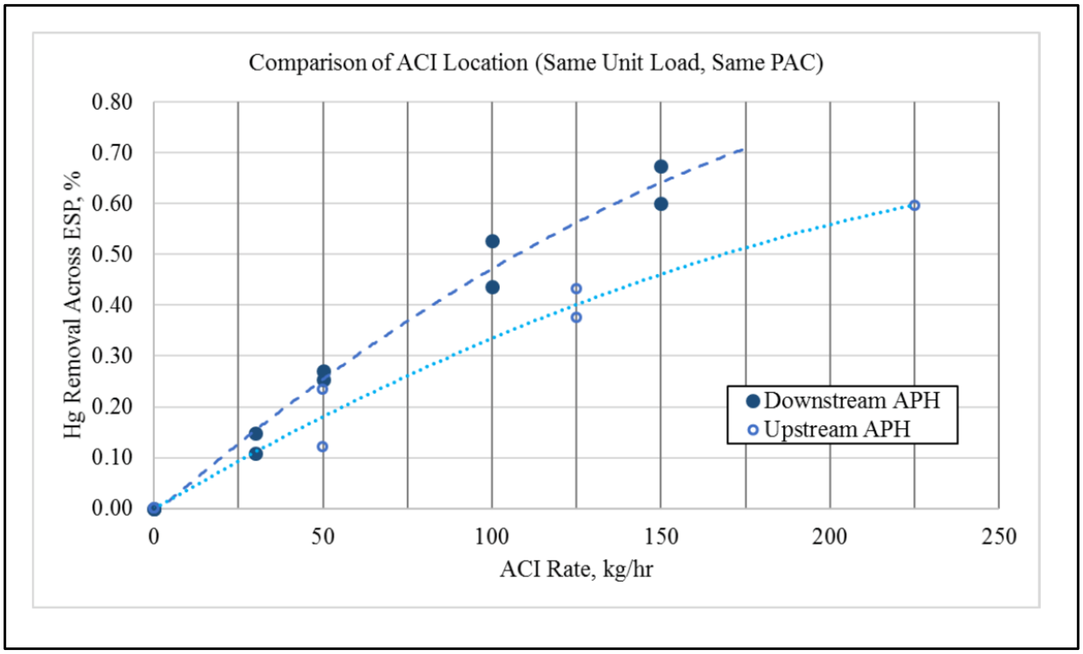


Figure 6-9. Sorbent Hg Removal in ESP in Lignite-Fired Unit: Effect of Injection Location

Data in Figure 6-9 show the role of $SO_3$ in compromising sorbent performance - highest Hg removal is attained with lower $SO_3$ (downstream APH) with 60-68% Hg removal achieved (at an injection rate corresponding to 0.6 lbs/MACF).

Attaining a total system 92% Hg removal – the target as described by EPA – is likely not achievable given the trajectory of the curves as shown in Figure 6-9.

## 6.4 EPA Cost Calculations Ignore FGD

EPA ignores the major role of wet or dry FGD in removing Hg – a fundamental flaw in their analysis. EPA's premise that sorbent addition is the sole compliance technology is incorrect – 18 of 22 units in the lignite fleet listed in Table 9 of the RTR Tech Memo are equipped with FGD.

[34] Sjostrom 2016. See graphic 16.

[35] Satterfield, J., Optimizing ACI Usage to Reduce Costs, Increase Fly Ash Quality, and Avoid Corrosion, presentation to the Powerplant Pollutant and Effluent Control Mega Symposium, August, 2018.

Of these 18 units, 4 are equipped with dry FGD and 14 with wet FGD. This process equipment asserts a major role in Hg removal as discussed in the next section.

The calculation of cost-effectiveness for the model plant as presented in Section (e)(i) of the RTR Tech memo addresses only sorbent addition, thus does not reflect the Hg compliance strategy of 18 units in the lignite fleet. EPA assumes (a) upgrade of sorbent from "conventional" activated carbon to the halogenated form, and (b) increasing sorbent injection from 2.5 to 5.0 lbs/MAFH elevates Hg reduction from 73% to 92%.[36] This assumption is not relevant – at least in this specific form – to 18 of 22 units in the lignite fleet, as wet or dry FGD will contribute to Hg removal. EPA's approach could underestimate the cost per ton incurred, as tons of Hg removed by the FGD could be credited to sorbent injection (the denominator of the $/ton calculation is larger than it should be).

The variable of FGD Hg removal cannot be ignored, and undermines the legitimacy of the cost estimates as Hg removed by FGD cannot be ascribed to sorbent injection. Thus, depending on how or if the sorbent injection rate changes, costs could increase beyond EPA's estimate (as the denominator in the $/ton calculation is reduced.

## 6.5 Conclusions

- EPA's proposal that Hg emissions of 1.2 lbs/TBtu can be attained for lignite-fired units by increasing sorbent injection rate and adding halogens (to compensate for loss of refined coal) is incorrect, as it assumes sorbent injection Hg removal observed with PRB is achievable on lignite.

- Flue gas generated from lignite exhibits measurable $SO_3$ in quantities that– as summarized by EPA's contractor for IPM model inputs - reduce the effectiveness of sorbent by 50% and in some cases presents a barrier to 90% Hg removal.

- Accounting for the variability of Hg content in lignite for most North Dakota and Texas lignite fuels, more than 90% Hg removal is required to meet 1.2 lbs/MBtu, exceeding the nominally 80% removal estimated by EPA, and over a 30-day rolling average basis is unlikely to be attained.

- EPA's calculation of cost–effectiveness for lignite fuels ignores the role of FGD, present in 18 of the 22 reference stations, in removing Hg. The result of this erroneous assumption could be an under-estimation of the cost for additional Hg removal.

[36] EPA uses the incorrect constant in the calculation of gas flow rate to translate sorbent injection from a mass per time basis (lb//hr) to mass per unit volume of gas (lbs/MACF). The calculation on page 24 uses the value of 9,860 scf/MBtu to quantify flue gas generated from lignite coal. Per EPA-454/R-95-015 (Procedure for Preparing Emission Factor Documents, OAQPS, November 1997) this value reflects the dry volume of gas produced from lignite coal, per MBtu. The flue gas rate that is processed by the environmental controls is the authentic "wet" basis and about 20% higher per MBtu (12,000 scf/MBtu). Use of the correct, latter constant lowers the value of sorbent per MACF by the same magnitude.

# 7. Mercury Emissions: Non-Low Rank Fuels

Section 7 addresses EPA's proposal to retain the present Hg limit of 1.2 lbs/TBtu for units firing bituminous and subbituminous coals.

EPA recognizes that Hg emission rates - as determined on an annual average basis - have decreased significantly since the initial MATS rule was issued, with bituminous–fired units averaging 0.4 lbs/TBtu (and ranging between 0.2 and 1.2 lbs/TBtu) and subbituminous-fired units averaging 0.6 lbs/TBtu (ranging between 0.1 to 1.2 lbs/TBtu).[37] EPA states these Hg emission rates represent between a 77 and 98% Hg removal from an assumed Hg inlet value of 5.5 lbs/TBtu. EPA notes they did not acquire detailed information on compliance steps such as the type of sorbent injected, the rate of sorbent injection, and the role of SCR NOx control and wet FGD and the myriad factors that determine Hg removal "co-benefits."

This section addresses the reported Hg removal and basis for EPA's position.

## 7.1 Hg Removal

EPA's discussion of the annual average of Hg removal does not consider the 30-day rolling average, the more challenging metric to attain – and the metric mandated for compliance. The 30-day rolling average reflects variability in Hg coal content and process conditions, both of which can experience daily or hourly changes, which obviously is not captured in annual averages.

Figures 7-1 and 7-2 report two metrics of Hg emission rate variability.[38] Figure 7-1 presents the mean and standard deviation of Hg annual average emissions for eleven categories of control technology and fuel rank. For six of these eleven categories, the sum of the mean and the standard deviation approach the Hg limit of 1.2 lbs/TBtu.

Figure 7-2 describes for six categories of control technology and 2 or 3 fuel ranks (depending on the technology) the number of units that for at least one operating day exceed 1.2 lbs/TBtu on a 30-day rolling average. Figure 7-2 shows for all categories of control technology and fuel rank experience 10% to 20% of units exceed this 30-day average.

In summary, EPA's report of annual Hg emission rate - significantly reduced compared from 2012 – does not provide a basis for further reductions as annual data does not account for variability.

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[37] Prepublication Version, page 85

[38] Cichanowicz, J. E. et. al., Mercury Emissions Rate: The Evolution of Control Technology Effectiveness, Presented at the Power Plant Pollutant and Effluent Control MEGA Symposium: Best Practices and Trends, August 20-23, 2018, Baltimore, MD.

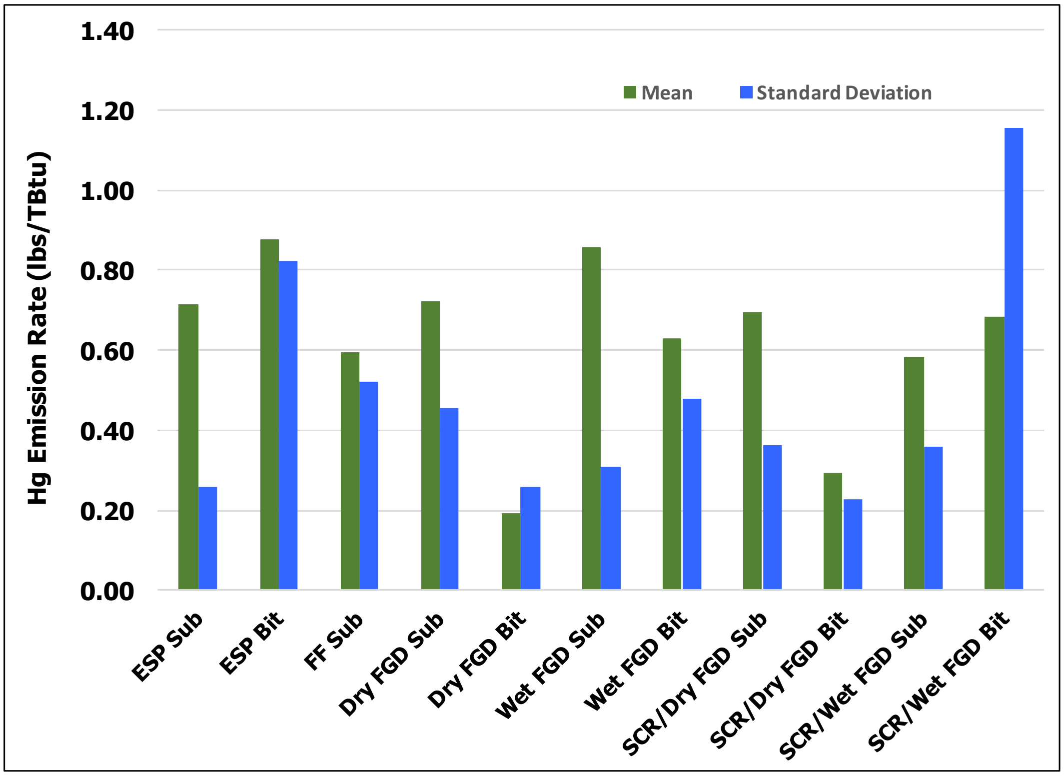


Figure 7-1. Mean, Standard Deviation of Annual Hg Emissions: 2018

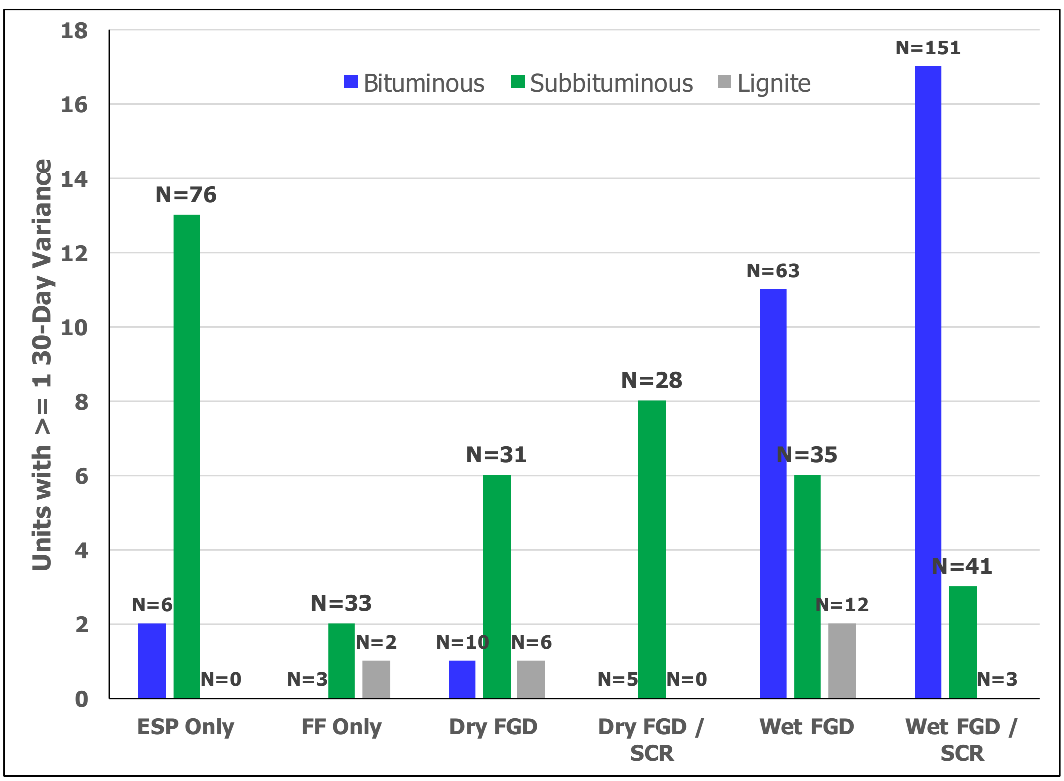


Figure 7-2. Mean, Standard Deviation of Annual Hg Emissions: 2018

## 7.2 Role of Fuel Composition and Process Conditions

Hg emissions are defined by variability in coal composition and process conditions, the latter including sorbent type, and injection rate, and the "co-benefit" Hg removal imparted by SCR NOx control and wet or dry FGD.

Although EPA did not elicit detailed process information from owners via Section 114, several key insights are presented in a 2018 survey conducted by ADA.[39]

### 7.2.1 Coal Variability

EPA cites observing for Hg emissions "a control range of 98 to 77 percent (assuming an average inlet concentration of 5.5 lb/TBtu)."[40] It is not clear if EPA assigns the average Hg content value of 5.5 lbs/TBtu to both bituminous and subbituminous coal, or solely the latter.

Figure 7-3 shows an average value of 5.5 lbs/TBtu does not represent either coal rank well. Figure 7-3 presents – on an annual average basis – data from more than 70 units reporting Hg content to the EIA. Numerous units report up to 10 lbs/TBtu - almost twice the average value EPA assigns, with 10 additional units reporting Hg content exceeding 10 lbs/TBtu. Northern Appalachian bituminous coals appear to contain higher Hg content than coals from other regions.

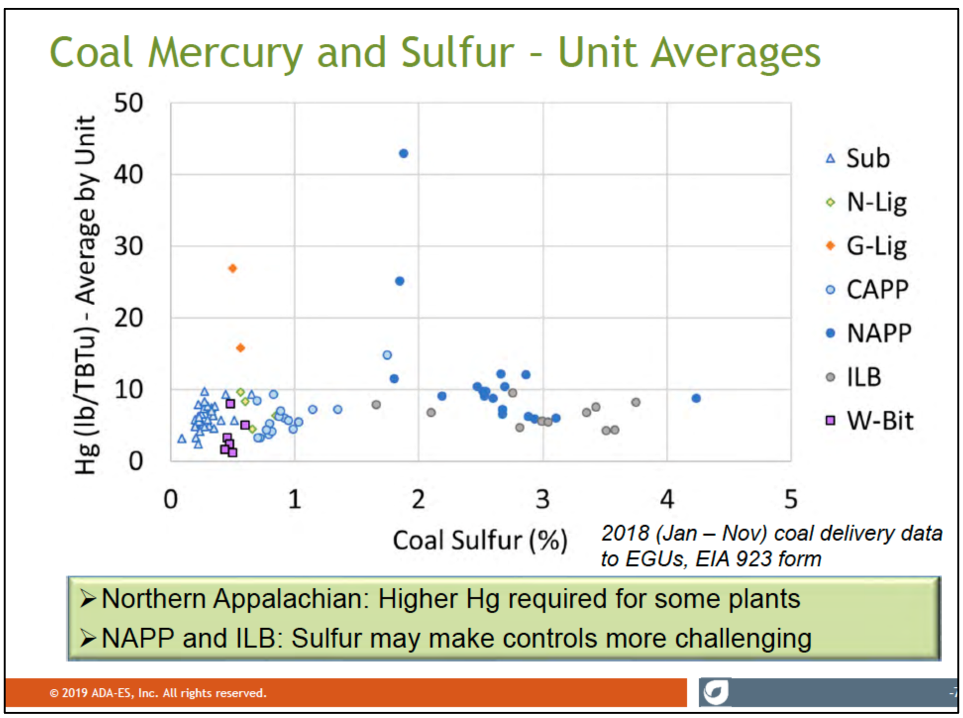


Figure 7-3. Annual Average of Fuel Hg, Sulfur Content in Coal

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39 Sjostrom, S. et. al., Mercury Control in the U.S.: 2018 Year in Review

40 RTR Tech Memo, page 19.

Consequently, EPA's calculation of 98 to 77% Hg removal is likely inaccurate as the assumed coal Hg content is too low.

### 7.2.2 Process Conditions

The process conditions for Hg removal: sorbent composition, sorbent injection rate, and the "co-benefits" of SCR NOx control and wet FGD are highly variable, due to a combination of factors. The following provides several examples.

Refined Coal. The absence of Refined Coal – no longer a viable option - complicates projecting future Hg emissions. A survey of Hg compliance activities for 2018 reported Refined Coal as a compliance step;[41] EIA fuel records show this trend persisted through 2021. EPA's assumption that adding halogens to the fuel or flue gas compensates for the unavailability of Refined Coal is speculative and without basis. *Without assurances of the benefits from the halogen content of Refined Coal, it is not possible to assess the viability of lowering Hg emissions.*

Sorbent Injection. Sorbent injection is a key compliance step for 70% of subbituminous-fired units, for some augmented with coal additives and Refined Coal. For bituminous-fired units, 18% of coal use is treated by some combination of sorbent injection and coal additives.

As described by EPA, increasing the rate of sorbent injection increases Hg removal – but with diminishing returns as sorbent mass is added. An example of this relationship is provided by full-scale tests at Ameren's PRB-fired Labadie Unit 3. These tests explored the effectiveness of both conventional and brominated activated carbon. These tests, purposely conducted in PRB-generated flue gas to define sorbent performance in the absence of $SO_3$, show Hg removal of 90% or more is feasible and that halogen addition can lower sorbent rate.[42]

This relationship is complicated by the role of Refined Coal, coal additives, and (as described below) the contribution of "co-benefits". *Devising a reasoned prediction of Hg removal under variable conditions, including coal composition and the impact of changing sorbents is not possible with current available information.*

SCR, FGD Co-Benefits. The capture of Hg by wet FGD – in many cases prompted by the role of SCR catalysts to oxidize elemental Hg – can be a primary mean for Hg capture. However, such co-benefits are highly variable, and depend on the ratio of elemental to oxidized Hg in the flue gas, and the consequential Hg "re-emission" by a wet FGD. There are means to remedy this variability in some instances, but broad success cannot be assured. *Without the specifics of FGD design and operation, Hg removal via wet FGD cannot be predicted.*

[41] Sjostrom, S. et. al., Mercury Control in the U.S.: 2018 Year in Review. Hereafter Sjostrom 2019.
[42] Senior, C. et. al., *Reducing Operating Costs and Risks of Hg Control with Fuel Additives*, Presentation to the Power Plant Pollutant Control and Carbon Management Mega Symposium, August 16-18, 2016.

Hg Re-Emission. The fate of Hg entering a wet FGD is uncertain.[43] If in the oxidized state, Hg upon entering the FGD solution can (a) remain in solution and be discharged with the FGD-cleansing step of "blowdown" (b) precipitate as a solid and be removed with the byproduct (typically gypsum), or (c) be reduced from the oxidized to the elemental state, thus re-emitted in the flue gas. Several means to minimize Hg re-emission exist, including injection of sulfite and controlling the scrubber liquor oxidation/reduction potential (ORP). These means can limit Hg remission but are additional process steps that are superimposed upon the task of achieving high efficiency $SO_2$ removal. *The extent these means can be universally applied without compromising $SO_2$ removal is uncertain.*

Role of Variability Due to Load Changes. An in-plant study showed that increasing load for a wet FGD-equipped unit can elevate Hg re-emission, eventually exceeding 1.2 lbs/TBtu.[44] This observation can be due to loss of the control over the ORP, defined in the previous paragraph as a key factor in FGD Hg removal. Chemical additives can adjust ORP but complete and autonomous control may not be available. For example, in a systematic evaluation of FGD operating variables conducted at a commercial power station, factors such as limestone composition and the extent to which units must operate in zero-water discharge – as perhaps mandated by the pending Effluent Limitation Guideline – can affect ORP and thus Hg-re-emission.[45]

Upsets in wet FGD process conditions can prompt Hg re-emission. Specifically, one observer noted two units that "….experienced a scrubber reemission event causing the mercury stack emissions to increase dramatically above the MATS limit and significantly higher than the incoming mercury in the coal and the event lasting for several days."[46] This high Hg event was eventually remedied over the short-term operation, but long-term performance is not available.

## 7.3 Conclusions: Mercury Emissions - Non-Low Rank Coals

There is inadequate basis to further lower the Hg emissions rate below the present limit of 1.2 lbs/TBtu, as variability in fuel and process operations outside the control of the operator can elevate emissions to approach or in some cases exceed that rate.

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[43] Gadgil, M., 20 Years of Mercury Re-emission – What do we Know?, Presentation to the Power Plant Pollutant Control and Carbon Management Mega Symposium, August 16-18, 2016.
[44] Blythe, G. et. al., Maximizing Co-Benefit Mercury Capture for MATS Compliance on Multiple Coal-Fired Units, Presentation to the Power Plant Pollutant Control and Carbon Management Conference Mega Symposium, August 16-18, 2016.
[45] Blyte, G. et. al., Investigation of Toxics Control by Wet FGD Systems, Presentation to the Power Plant Pollutant Control and Carbon Management Conference Mega Symposium, August 16-18, 2016.
[46] Pavlisch, J. et. al., Managing Mercury Reemission and Managing MATS compliance Using a sorbent Approach, Presentation to the Power Plant Pollutant Control and Carbon Management Conference Mega Symposium, August 16-18, 2016.

# 8. EPA IPM RESULTS: EVALUATION AND CRITIQUE

EPA used the Integrated Planning Model (IPM) to establish a Baseline Scenario from which to measure compliance impacts of the proposed rule. This Baseline Scenario is premised upon IPM's Post-IRA 2022 Reference Case. In this Post-IRA simulation, IPM evaluated a number of tax credit provisions of the Inflation Reduction Act of 2022 (IRA), which address application of Carbon Capture and Storage (CCS) and other means to mitigate carbon dioxide ($CO_2$). These are the (i) New Clean Electricity Production Tax Credit (45Y); (ii) New Clean Electricity Investment Credit (48E); Manufacturing Production Credit (45X); CCS Credit (45Q); Nuclear Production Credit (45U); and Production of Clean Hydrogen (45V). Also, the Post-IRA 2022 Reference Case includes compliance with the proposed Good Neighbor Policy (Transport Rule).[47]

A critique of EPA's methodology and findings is described subsequently.

## 8.1 IPM 2030 Post-IRA 2022 Reference Case: A Flawed Baseline

The IPM Post-IRA 2022 Reference Case for the years 2028 and 2030 comprises a flawed baseline to measure compliance impacts of the proposed rule. This flawed baseline centers around IPM projected coal retirements in both 2028 and 2030 as well as units projected to deploy CCS in 2030. Specifically, IPM has erroneously retired numerous coal units expected to operate beyond 2028 and 2030 based upon current announced retirement plans; consequently, these units are subject to the proposed rule beginning in 2028. There are numerous challenges and limitations to deploying CCS as EPA has projected on 27 coal units in 2030. These units would also be subject to the proposed. Consequently, IPM's compliance impacts of the proposed rule is likely understated.

### 8.1.1 Analytical Approach

This analysis identifies those units IPM modeled as coal retirements, CCS retrofits and coal to gas (C2G) conversions in both 2028 and 2030, and compares them to announced plans for unit retirements, technology retrofits and C2G conversions. To identify errors for 2028, the parsed file for the 2028 Post-IRA 2022 Reference Case was used. Since EPA did not provide a parsed

[47] In addition to the IRA and GNP, the Post-IRA 2022 Reference Case takes into account compliance with the following: (i) Revised Cross-State Air Pollution Rule (CSAPR) Update Rule; (ii) Standards of Performance for Greenhouse Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Utility Generating Units; (iii) MATS Rule which was finalized in 2011; (iv) Various current and existing state regulations; (v) Current and existing RPS and Current Energy Standards; (vi) Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART); and, (vii) Platform reflects California AB 32 and RGGI. Three non-air federal rules affecting EGUs: (i) Cooling Water Intakes (316(b) Rule; (ii) Coal Combustion Residuals (CCR), which reflects EPA's July 29, 2020 position on retrofitting or closure of surface impoundments; and, (iii) Effluent Limitation Guidelines, which includes the 2020 Steam Electric Reconsideration Rule (cost adders were applied starting in 2025).

file of the 2030 Post-IRA 2022 Reference Case, an abbreviated parsed file was created using four different IPM files. These are: (i) 2028 parsed file of the Post-IRA 2022 Reference Case; (ii) Post-IRA 2022 Reference Case RPE File for the year 2030; (iii) Post-IRA 2022 Reference Case RPT Capacity Retrofits File for the year 2030; and, (iv) National Electrical Energy Data System (NEEDS) file for the Post-IRA 2022 Reference Case. These parsed files allow identifying IPM modeled retirements in 2028 and 2030, CCS retrofits in 2030 and C2G in both 2028 and 2030. These modeled retirements and conversions were compared to announced information in the James Marchetti Inc ZEEMS Data Base.

### *8.1.2* Coal Retirements

The 2028 IPM modeling run retired 112 coal units (53.6 GW) from 2023 to 2028. In the 2030 analysis, IPM retired an additional 52 coal units (25.5 GW). The total number of retirements for the two modeling run years is 164 coal units (79.1 GW).

Table 8-1 summarizes the IPM retirement errors in the 2028 and 2030 modeling runs. Specifically, IPM incorrectly retired 29 coal units (14.0 GW) by 2028 and an additional 23 coal units (14.1 GW) in 2030. In addition, there are 3 coal units (1.6 GW) that EPA listed in the NEEDS file as being retired before 2028 that will operate beyond 2030. In total, there are 55 coal units that IPM erroneously retired in the 2028 and 2030 modeling runs that will be operating and subject to some aspect of the proposed rule beginning in 2028.

Table 8-1. Coal Retirement Errors

| Year | Description | Number |
|---|---|---|
| **2028** | Retiring after 2028 | 29 |
| **2030** | Retiring after 2030 | 23 |
| **2030** | NEEDS retirements that should be in the 2030 modeling platform | 3 |
| **Total** | | 55 |

Tables 8-2 to 8-6 lists each of the coal units IPM has incorrectly retired, incorrectly deployed CCS, or switched to natural gas.

Table 8-2. IPM Coal Retirement Errors: 2028 Post-IRA 2022 Reference Case Run

| No. | RegionName | StateName | ORISCode | UnitID | PlantName | Capacity | Observation |
|---|---|---|---|---|---|---|---|
| 1 | WECC_Arizona | Arizona | 6177 | U1B | Coronado | 380 | To be retired by 2032 and continued seasonal curtailemts, |
| 2 | SPP West | Arkansas | 6138 | 1 | Flint Creek | 528 | Retire January 1, 2039 - Entergy LL 2023 IRP (March 31, 2023). |
| 3 | MISO_Arkansas | Arkansas | 6641 | 1 | Independence | 809 | Agreement with Sierra Club and NPCA to cease coal by Dec 31, 2030. |
| 4 | MISO_Arkansas | Arkansas | 6641 | 2 | Independence | 842 | Agreement with Sierra Club and NPCA to cease coal by Dec 31, 2030. |
| 5 | SERC_Central_TVA | Kentucky | 1379 | 2 | Shawnee | 134 | TVA planning assumption retirement (5/21) - December 31, 2033 |
| 6 | SERC_Central_TVA | Kentucky | 1379 | 3 | Shawnee | 134 | TVA planning assumption retirement (5/21) - December 31, 2033 |
| 7 | SERC_Central_TVA | Kentucky | 1379 | 5 | Shawnee | 134 | TVA planning assumption retirement (5/21) - December 31, 2033 |
| 8 | SERC_Central_TVA | Kentucky | 1379 | 6 | Shawnee | 134 | TVA planning assumption retirement (5/21) - December 31, 2033 |
| 9 | SERC_Central_TVA | Kentucky | 1379 | 7 | Shawnee | 134 | TVA planning assumption retirement (5/21) - December 31, 2033 |
| 10 | SERC_Central_TVA | Kentucky | 1379 | 8 | Shawnee | 134 | TVA planning assumption retirement (5/21) - December 31, 2033 |
| 11 | SERC_Central_TVA | Kentucky | 1379 | 9 | Shawnee | 134 | TVA planning assumption retirement (5/21) - December 31, 2033 |
| 12 | MISO_Minn/Wisconsin | Minnesota | 6090 | 3 | Sherburne County | 876 | PSC approved closure (2/8/22). Upper Midwest Resource Plan (6/25/21) for 2030. |
| 13 | MISO_Missouri | Missouri | 2103 | 1 | Labadie | 593 | 2022 IRP Update retire in 2042 (6/24/22). |
| 14 | MISO_Missouri | Missouri | 2103 | 2 | Labadie | 593 | 2022 IRP Update retire in 2042 (6/24/22). |
| 15 | MISO_Missouri | Missouri | 2103 | 3 | Labadie | 593 | 2022 IRP Update (6/24/22) retirement in 2036 |
| 16 | MISO_Missouri | Missouri | 2103 | 4 | Labadie | 593 | 2022 IRP Update (6/24/22) retirement in 2036 |
| 17 | MISO_Missouri | Missouri | 2107 | 1 | Sioux | 487 | 2022 IRP Update (6/24/22) - To be retired in 2030 |
| 18 | MISO_Missouri | Missouri | 2107 | 2 | Sioux | 487 | 2022 IRP Update (6/24/22) - To be retired in 2030 |
| 19 | SERC_VACAR | North Carolina | 2712 | 3A.3B | Roxboro | 694 | 2022 Carbon Reduction Plan per PSC retirement Jan. 1, 2028-34 (12/30/22). |
| 20 | SERC_VACAR | North Carolina | 2712 | 4A, 4B | Roxboro | 698 | 2023 Carbon Reduction Plan per PSC retirement Jan. 1, 2028-34 (12/30/22). |
| 21 | ERCOT_Rest | Texas | 298 | LIM1 | Limestone | 831 | EIA 860 has retirement December 2029 |
| 22 | ERCOT_Rest | Texas | 298 | LIM2 | Limestone | 858 | EIA 860 has retirement December 2029 |
| 23 | WECC_Utah | Utah | 7790 | 1-1 | Bonanza | 458 | Unit is planned to retire in 2030, |
| 24 | WECC_Utah | Utah | 8069 | 2 | Huntington | 450 | Retire in 2032 - 2023 IRP (3/31/23) |
| 25 | PJM_Dominion | Virginia | 7213 | 1 | Clover | 440 | Dominion 2023 IRP - Retirement Date 2040 (5/1/23) |
| 26 | PJM_Dominion | Virginia | 7213 | 2 | Clover | 437 | Dominion 2023 IRP - Retirement Date 2040 (5/1/23) |
| 27 | PJM_AP | West Virginia | 3943 | 1 | Fort Martin | 552 | EPA Settlement on wastewater upgrades (8/9/22). 2020 IRP through 2035 |
| 28 | PJM_AP | West Virginia | 3943 | 2 | Fort Martin | 546 | EPA Settlement on wastewater upgrades (8/9/22). 2020 IRP through 2036 |
| 29 | WECC_Wyoming | Wyoming | 6101 | BW91 | Wyodak | 332 | Retire in 2039 - IRP (3/31/23) |

Table 8-3. IPM Coal Retirement Errors: 2030 Post IRA 2022 Reference Case Modeling Run

| No. | RegionName | StateName | ORISCode | UnitID | PlantName | Capacity | Observations |
|---|---|---|---|---|---|---|---|
| 1 | WECC_Arizona | Arizona | 6177 | U2B | Coronado | 382 | To be retired by 2032 and contined seasonal curtailments |
| 2 | FRCC | Florida | 628 | 4 | Crystal River | 712 | To be retired in 2034 (2020 Sustainability Report) |
| 3 | FRCC | Florida | 628 | 5 | Crystal River | 710 | To be retired in 2034 (2020 Sustainability Report) |
| 4 | SERC_Southeastern | Georgia | 6257 | 1 | Scherer | 860 | ELG Compliance - Wastewater Treatment - No Announced Retirement |
| 5 | SERC_Southeastern | Georgia | 6257 | 2 | Scherer | 860 | ELG Compliance - Wastewater Treatment - No Announced Retirement |
| 6 | PJM West | Indiana | 1040 | 1 | Whitewater Valley | 35 | Biased to peak load duty. 2020 IRP Base Case has retirement May 31, 2034 |
| 7 | MISO_Iowa | Iowa | 1167 | 9 | Muscatine Plant #1 | 163 | ELG compliance options for FGDW and BATW, possible 2028 retirement |
| 8 | SPP North | Kansas | 6068 | 1 | Jeffrey Energy Center | 728 | To be retired at the end of 2039 (2021 IRP) |
| 9 | SPP North | Kansas | 1241 | 2 | La Cygne | 662 | To be retired at the end of 2039 (2021 IRP) |
| 10 | SERC_Central_Kentucky | Kentucky | 1356 | 1 | Ghent | 474 | To be retired 2034 |
| 11 | SERC_Central_Kentucky | Kentucky | 1356 | 3 | Ghent | 485 | To be retired 2037. |
| 12 | SERC_Central_Kentucky | Kentucky | 1356 | 4 | Ghent | 465 | To be retired 2037. |
| 13 | SPP North | Missouri | 6065 | 1 | Iatan | 700 | To be retired at the end of 2039 (2021 IRP) |
| 14 | SPP North | Missouri | 6195 | 1 | John Twitty | 184 | Beyond 2030 retirement date - new 2022 IRP |
| 15 | SERC_VACAR | North Carolina | 8042 | 1 | Belews Creek | 1110 | 1/1/2036 retirement per 2022 Carbon Reduction Plan |
| 16 | SERC_VACAR | North Carolina | 8042 | 2 | Belews Creek | 1110 | 1/1/2036 retirement per 2022 Carbon Reduction Plan |
| 17 | SERC_VACAR | North Carolina | 2727 | 3 | Marshall (NC) | 658 | 2022 Carbon Reduction Plan accepted by PSC retirement Jan. 1, 2033 (12/30/22) |
| 18 | SERC_VACAR | North Carolina | 2727 | 4 | Marshall (NC) | 660 | 2022 Carbon Reduction Plan accepted by PSC retirement Jan. 1, 2033 (12/30/22) |
| 19 | MISO_MT, SD, ND | North Dakota | 8222 | B1 | Coyote | 429 | Active perl reliablity concerns in MISO. End of depreciable life - 2041 |
| 20 | SERC_VACAR | South Carolina | 6249 | 1 | Winyah | 275 | 2023 IRP: operate unit through 2030 for reliability (4/19/23) |
| 21 | SERC_VACAR | South Carolina | 6249 | 2 | Winyah | 285 | 2024 IRP: operate unit through 2030 for reliability (4/19/23) |
| 22 | SERC_VACAR | South Carolina | 6249 | 3 | Winyah | 285 | 2025 IRP: operate unit through 2030 for reliability (4/19/23) |
| 23 | SERC_VACAR | South Carolina | 6249 | 4 | Winyah | 285 | 2026 IRP: operate unit through 2030 for reliability (4/19/23) |
| 24 | PJM West | West Virginia | 3935 | 1 | John E Amos | 800 | Approved ELG upgrades to keep plant open until 2040. |
| 25 | PJM West | West Virginia | 3935 | 2 | John E Amos | 800 | Approved ELG upgrades to keep plant open until 2040. |
| 26 | PJM_AP | West Virginia | 3954 | 1 | Mt Storm | 554 | Dominion 2023 IRP - Retirement Date 2044 (5/1/23) |
| 27 | PJM_AP | West Virginia | 3954 | 2 | Mt Storm | 555 | Dominion 2023 IRP - Retirement Date 2044 (5/1/23) |

Table 8-4 Units in the NEEDS to Be Operating in 2028

| No. | Region Name | State Name | ORIS Plant | Unit ID | Plant Name | Capacity (MW) | NEEDS Retirement Year | Observations |
|---|---|---|---|---|---|---|---|---|
| 1 | SPP_N | Kansas | 1241 | 1 | La Cygne | 736 | 2025 | 2022 IRP Update to be retired in 2032 |
| 2 | MIS_LA | Louisiana | 6190 | 3-1, 3-2 | Brame Energy Center | 626 | 2027 | No plans to retire. Evaluating CCS |
| 3 | WECC_WY | Wyoming | 4158 | BW44 | Dave Johnston | 330 | 2027 | Retire in 2039 - 2023 IRP (3/31/23). |

## Table 8-5 Units IPM Predicts CCS By 2030

| No. | Region Name | StateName | ORISCode | UnitID | PlantName | Capacity | Observations |
|---|---|---|---|---|---|---|---|
| 1 | ERCOT_Rest | Texas | 6179 | 3 | Fayette Power Project | 286.05 | |
| 2 | ERCOT_Rest | Texas | 7097 | BLR2 | J K Spruce | 537.93 | Board voted to convert to natural gas by 2027 (1/23/23) |
| 3 | ERCOT_Rest | Texas | 6180 | 1 | Oak Grove (TX) | 572.77 | |
| 4 | ERCOT_Rest | Texas | 6180 | 2 | Oak Grove (TX) | 570.97 | |
| 5 | ERCOT_Rest | Texas | 6183 | SM-1 | San Miguel | 237.74 | |
| 6 | FRCC | Florida | 645 | BB04 | Big Bend | 292.27 | |
| 7 | MISO_Indiana | Indiana | 6113 | 1 | Gibson | 594.24 | |
| 8 | PJM West | Kentucky | 6018 | 2 | East Bend | 399.00 | |
| 9 | PJM West | West Virginia | 3948 | 1 | Mitchell (WV) | 537.77 | |
| 10 | PJM West | West Virginia | 3948 | 2 | Mitchell (WV) | 537.77 | |
| 11 | SERC_Southeastern | Alabama | 6002 | 4 | James H Miller Jr | 477.05 | |
| 12 | SPP_WAUE | North Dakota | 6469 | B1 | Antelope Valley | 289.22 | |
| 13 | SPP_WAUE | North Dakota | 6469 | B2 | Antelope Valley | 288.38 | |
| 14 | SPP_WAUE | North Dakota | 2817 | 2 | Leland Olds | 279.16 | |
| 15 | WECC_Arizona | Arizona | 8223 | 3 | Springerville | 281.05 | |
| 16 | WECC_Arizona | Arizona | 8223 | 4 | Springerville | 281.05 | |
| 17 | WECC_Colorado | Colorado | 470 | 3 | Comanche (CO) | 501.15 | To be retired Dec 31 2030 (10/31/22) |
| 18 | WECC_Colorado | Colorado | 6021 | C3 | Craig (CO) | 305.66 | To be retired Dec 2029 - Electric Resource Plan (12/1/20) |
| 19 | WECC_Utah | Utah | 6165 | 1 | Hunter | 319.80 | Retire in 2031- 2023 IRP (3/31/23) |
| 20 | WECC_Utah | Utah | 6165 | 2 | Hunter | 292.44 | Retire in 2032 - 2023 IRP (3/31/23). |
| 21 | WECC_Utah | Utah | 6165 | 3 | Hunter | 314.06 | Retire in 2032 - 2023 IRP (3/31/23). |
| 22 | WECC_Utah | Utah | 8069 | 1 | Huntington | 311.54 | Retire in 2032 - 2023 IRP (3/31/23). |
| 23 | WECC_Wyoming | Wyoming | 8066 | BW73 | Jim Bridger | 354.02 | Convert to natural gas in 2030 - 2023 IRP (3/31/23) |
| 24 | WECC_Wyoming | Wyoming | 8066 | BW74 | Jim Bridger | 349.78 | Convert to natural gas in 2030 - 2023 IRP (3/31/23) |
| 25 | WECC_Wyoming | Wyoming | 6204 | 1 | Laramie River Station | 385.22 | |
| 26 | WECC_Wyoming | Wyoming | 6204 | 2 | Laramie River Station | 382.92 | |
| 27 | WECC_Wyoming | Wyoming | 6204 | 3 | Laramie River Station | 383.45 | |

## Table 8-6 Units IPM Erroneously Predicts Switch to Natural Gas

| No. | RegionName | StateName | ORISCode | UnitID | PlantName | Year | Capacity | Observations |
|---|---|---|---|---|---|---|---|---|
| 1 | SPP West (Oklahoma, | Arkansas | 56564 | 1 | John W Turk Jr Power Plant | 2030 | 609 | Retire Jan 1, 2068 - SWEPCO 2023 IRP (March 29, 2023) |
| 2 | PJM West | Kentucky | 6041 | 2 | H L Spurlock | 2028 | 510 | No announced C2G or co-firing |
| 3 | ERCOT_Rest | Texas | 56611 | S01 | Sandy Creek Energy Station | 2030 | 933 | No announced conversion |

#### 8.1.3 Coal CCS

Table 8-5 identifies the 27 units IPM projected to retrofit CCS by 2030; none of these have been involved in any Front-End Engineering and Design (FEED) Studies. However, 9 of the units identified by IPM will be either be retired or converted to natural gas in and around 2030. There are major questions addressing infrastructure and project implementation that present challenges to IPM's CCS projection for 2030. Indeed, it is next to impossible for these units to be in position to retrofit CCS by 2030.

#### *8.1.4* Coal to Gas Conversions (C2G)

The 2028 IPM modeling run converted 36 coal units to gas (14.3 GW). In the 2030 IPM modeling run an additional 2 coal units (1.5 GW) were converted to gas (Turk and Sandy Creek). As shown in Table 8.6, three of these units have no announced plans to convert to gas by 2028 or 2030 and will be subject to the proposed rule.

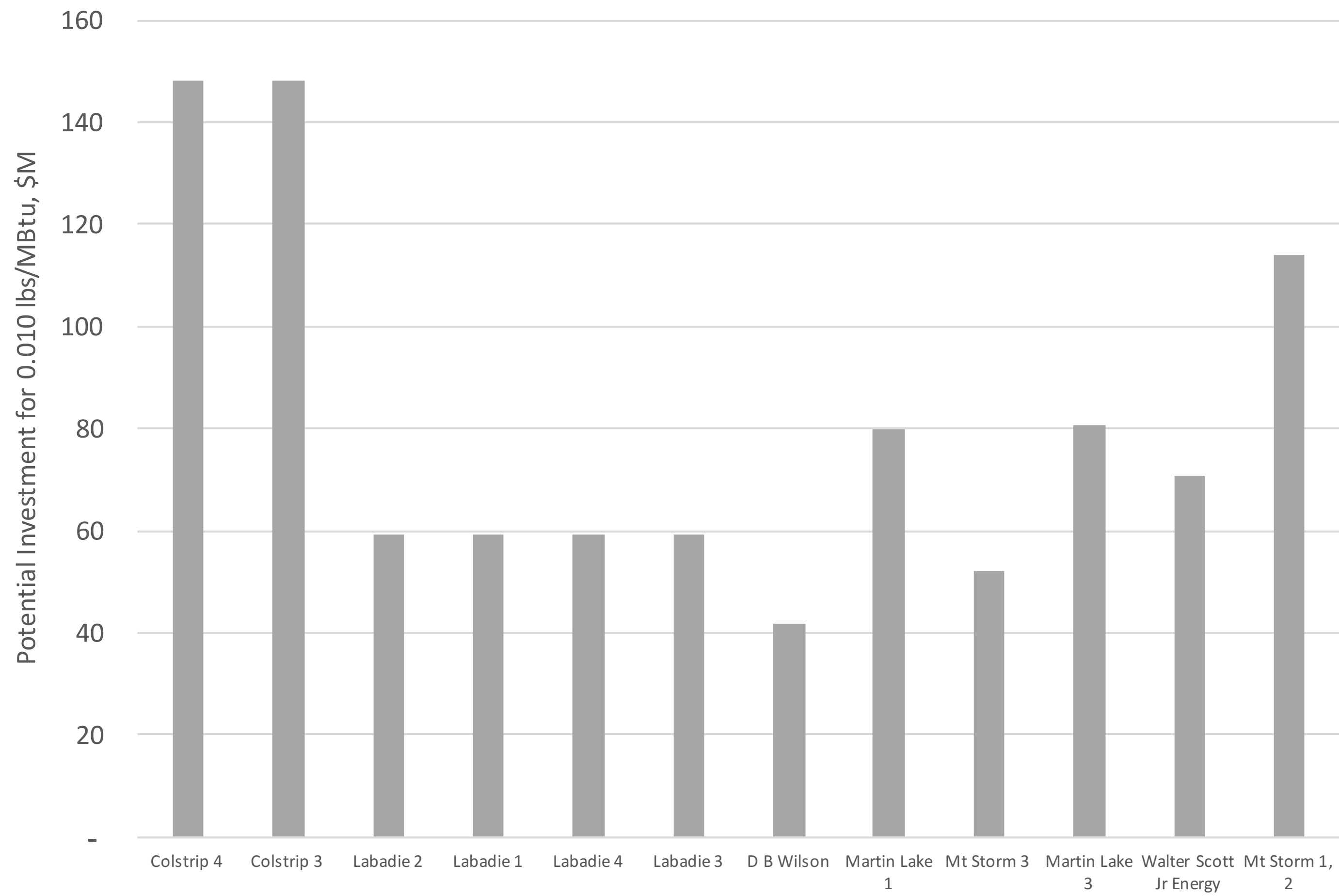
### 8.2 Summary

The major issues associated with EPA's IPM modeling of the 2028 and 2030 Post-IRA 2022 Reference Case are summarized as follows:

- The 2028 and 2030 Baseline (Post-IRA 2022 Reference Case) used to measure the compliance impacts of proposed rule is flawed and needs to be revised
- Most notably, IPM erred in retiring 55 coal units that will be subject to the proposed rule beginning in 2028.
- IPM retrofitted 27 units with CCS in 2030, 19 of which will be subject to the proposed rule. It is next to impossible for these units to retrofit CCS by 2030.
- The IPM modeled compliance impacts for the proposed rule in 2028 and 2030 is very likely understated.

# Appendix A: Additional Cost Study Data

Figure A-1. Unit ESP Investment (per EPA's Cost Assumptions): PM of 0.010 lbs/MBtu




Note: Colstrip costs reflect EPA's approch of retrofitting a fabric filter, as an ESP is not installed at that site.

Table A-1. Technology Assignment for 0.010 lbs/MBtu PM Rate: Industry Study

| ESP Minor | ESP Typical | ESP Major Upgrade | FF Cleaning | FF Retrofit |
|---|---|---|---|---|
| **Alcoa/Warrick** | East Bend | D B Wilson | Boswell Energy Center | Colstrip 3, 4 |
| **Big Bend** | General James M Gavin | Labadie | Clover Power Project | |
| **Coronado** | Gibson | Labadie | Ghent | |
| **Coronado** | Martin Lake 2 | Labadie | Gilberton Power/John B Rich | |
| **Crystal River** | Milton R Young | Labadie | H L Spurlock | |
| **Crystal River** | Mt Storm | Martin Lake 1 | Iatan | |
| **Jeffrey Energy Center** | Mt Storm | | Marion | |
| **Laramie River Station** | | | Mt Carmel Cogen | |
| **Martin Lake** | | | St Nicholas Cogen Project | |
| **San Miguel** | | | Walter Scott Jr Energy Center | |
| **Seminole** | | | WPS Westwood Generation LLC | |

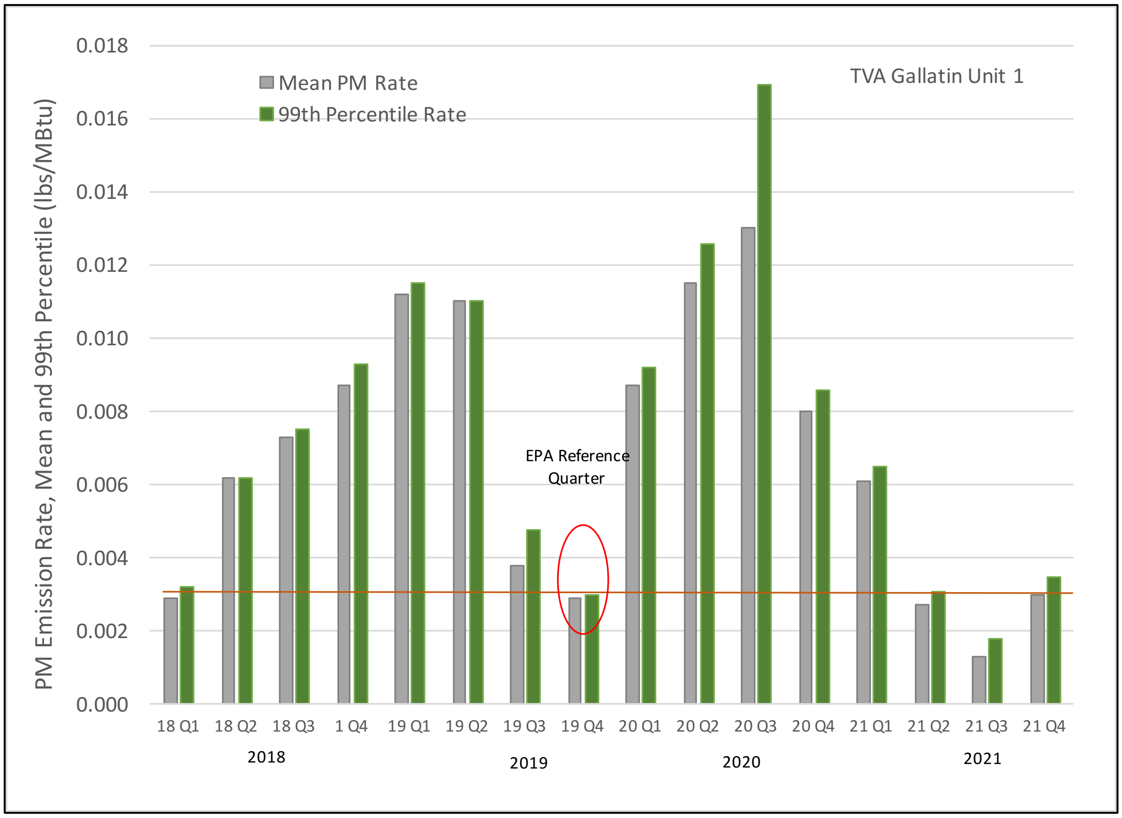
Table A-2 Technology Assignment for 0.006 lbs/MBtu PM Rate: Industry Study

| FF O&M Enhancement | FF Retrofit | FF Retrofit |
|---|---|---|
| Antelope Valley | Alcoa/Warrick | Laramie River Station |
| Bonanza | Belews Creek | Leland Olds 1, 2 |
| Boswell Energy Center Clay Boswell | Big Bend | Martin Lake 1-3 |
| Clover Power Project | Cardinal | Merrimack |
| Comanche | Colstrip 3, 4 | Milton R Young |
| Ghent | Coronado 1, 2 | Monroe 1, 2 |
| Gilberton Power/John B Rich | Crystal River 4, 5 | Mt Storm 1, 2 |
| H L Spurlock | D B Wilson | Naughton |
| Huntington | East Bend | Nebraska City |
| Iatan | General James M Gavin | R D Green |
| Louisa | Gibson 1, 3 | R S Nelson |
| Marion | Gibson | Sam Seymour Fayette 1, 2 |
| Mt Carmel Cogen | Independence | San Miguel |
| Oak Grove 1 | IPL - AES Petersburg | Schiller |
| Sandy Creek Energy Station | James H Miller Jr | Seminole |
| Scrubgrass Generating 1, 2 | Jeffrey Energy Center 1, 2, 3 | Trimble County |
| St Nicholas Cogen Project | Jim Bridger 3, 4 | Whelan Energy Center |
| Twin Oaks Power 1, 2 | Labadie 1 -4 | White Bluff 1, 2 |
| Walter Scott Jr Energy Center | | |
| Weston | | |
| WPS Westwood Generation LLC | | |

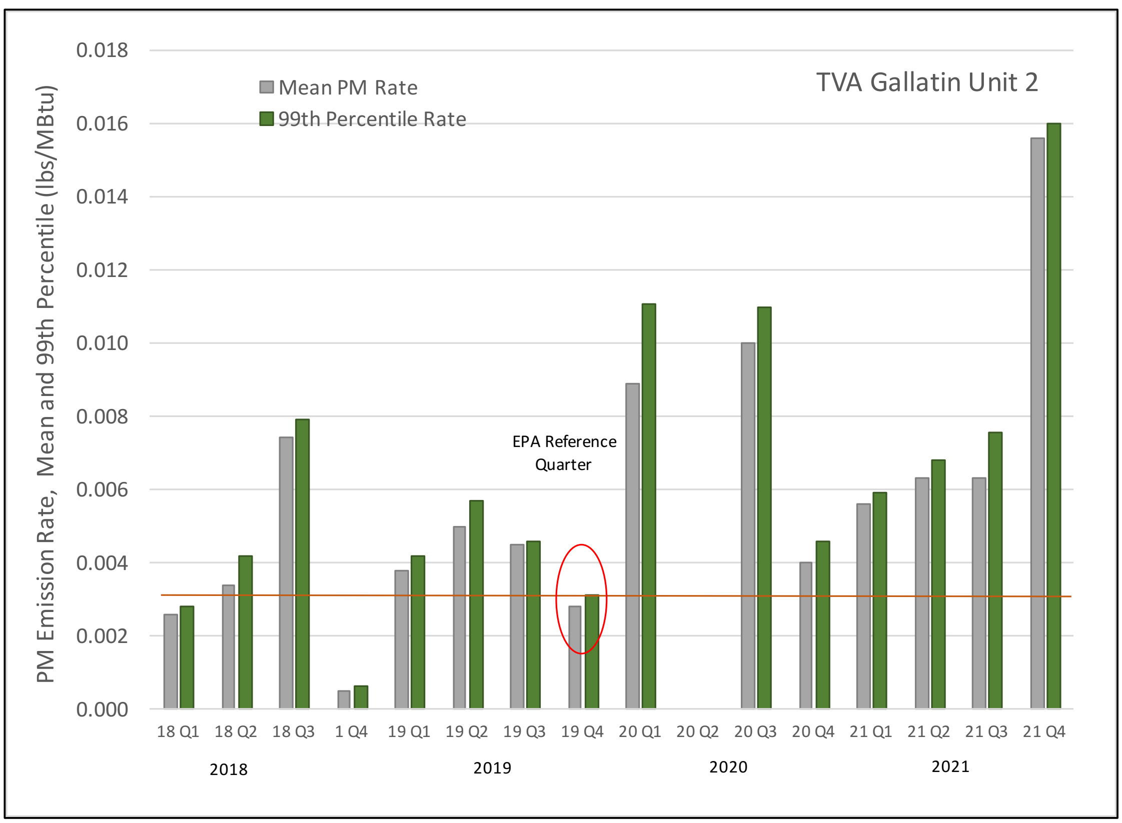
## Appendix B: Example Data Chart

Appendix A presents additional examples of units for which EPA's PM sampling and evaluation approach distorted results. These charts contain both mean and 99$^{th}$ percentile data. Data is presented for the following units, for which observations are offered as follows:

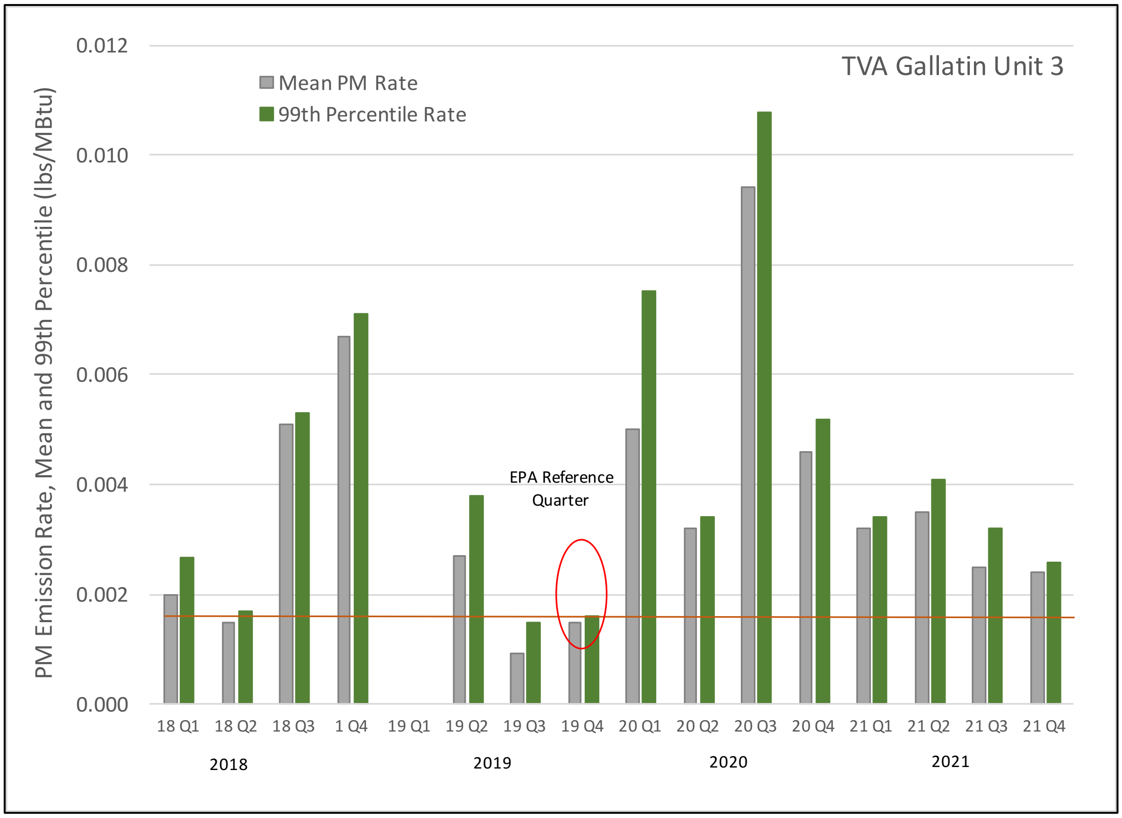
- TVA Gallatin Unit 1. EPA selected 0.0030 lbs/MBtu as the reference PM rate, using Q4 of 2019. Few of the 16 quarters that report lower PM emissions.
- TVA Gallatin Unit 2. EPA selected 0.0031 lbs/MBtu as the reference PM rate, also using Q4 of 2019. Few of the 16 quarters that report lower PM, similar to Unit 1.
- TVA Gallatin Unit 3. EPA selected 0.0016 lbs/MBtu as the reference PM rate, again using Q4 of 2019. Only one quarter (Q3 of 2019) reports lower PM rate.
- TVA Gallatin Unit 4. EPA selected 0.0022 lbs/MBtu as the reference PM rate, using Q1 of 2021. Of the 14 quarters reporting data, two quarters report PM rates equal to this rate, while two are below this rate.
- LG&E/KU Ghent 1. EPA selected 0.005 lbs/MBtu as the reference PM rate, using Q2 of 2019. This PM rate represents that reported in previous quarters, but with one exception all subsequent quarters through 2021 report higher PM.
- LG&E/KU Mill Creek Unit 4. EPA selected 0.0035 lbs/MBtu as the reference PM rate, using Q4 of 2021. With the exception of the previous quarter, this value is the lowest of any reported since 2017 by a significant margin.
- Alabama Power Gaston Unit 5. EPA selected 0.005 lbs/MBtu as the reference PM rate, using Q1 of 2021. Data for this unit is displayed from Q1 2017 through Q4 2022. Of the 24 reporting quarters (1Q 2017 through 4QW 2022) only 6 quarters have lower PM rates.
- Alabama Power Miller Unit 1. EPA selected 0.004 lbs/MBtu as the reference PM rate, using Q3 of 2017. Data for this unit is displayed from Q1 2017 through Q4 2022. The designated rate represents a significant reduction from approximately half of the reporting quarters since Q1 2020.

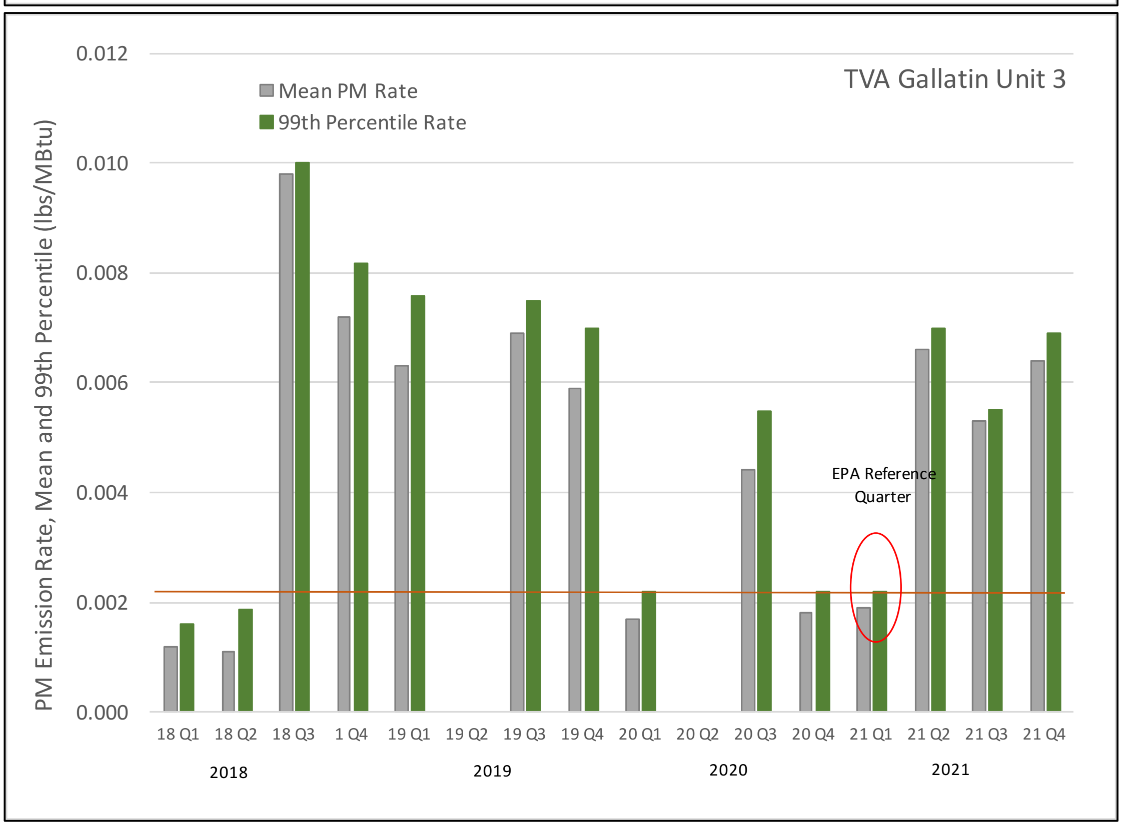


0.018
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
Mean PM Rate
99th Percentile Rate
TVA Gallatin Unit 1
EPA Reference Quarter
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
18 Q1
18 Q2
18 Q3
1 Q4
19 Q1
19 Q2
19 Q3
19 Q4
20 Q1
20 Q2
20 Q3
20 Q4
21 Q1
21 Q2
21 Q3
21 Q4
2018
2019
2020
2021

0.018
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
Mean PM Rate
99th Percentile Rate
TVA Gallatin Unit 2
EPA Reference Quarter
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
18 Q1
18 Q2
18 Q3
1 Q4
19 Q1
19 Q2
19 Q3
19 Q4
20 Q1
20 Q2
20 Q3
20 Q4
21 Q1
21 Q2
21 Q3
21 Q4
2018
2019
2020
2021


TVA Gallatin Unit 3
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.012
0.010
0.008
0.006
0.004
0.002
0.000
EPA Reference Quarter
18 Q1 18 Q2 18 Q3 1 Q4 19 Q1 19 Q2 19 Q3 19 Q4 20 Q1 20 Q2 20 Q3 20 Q4 21 Q1 21 Q2 21 Q3 21 Q4
2018
2019
2020
2021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Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
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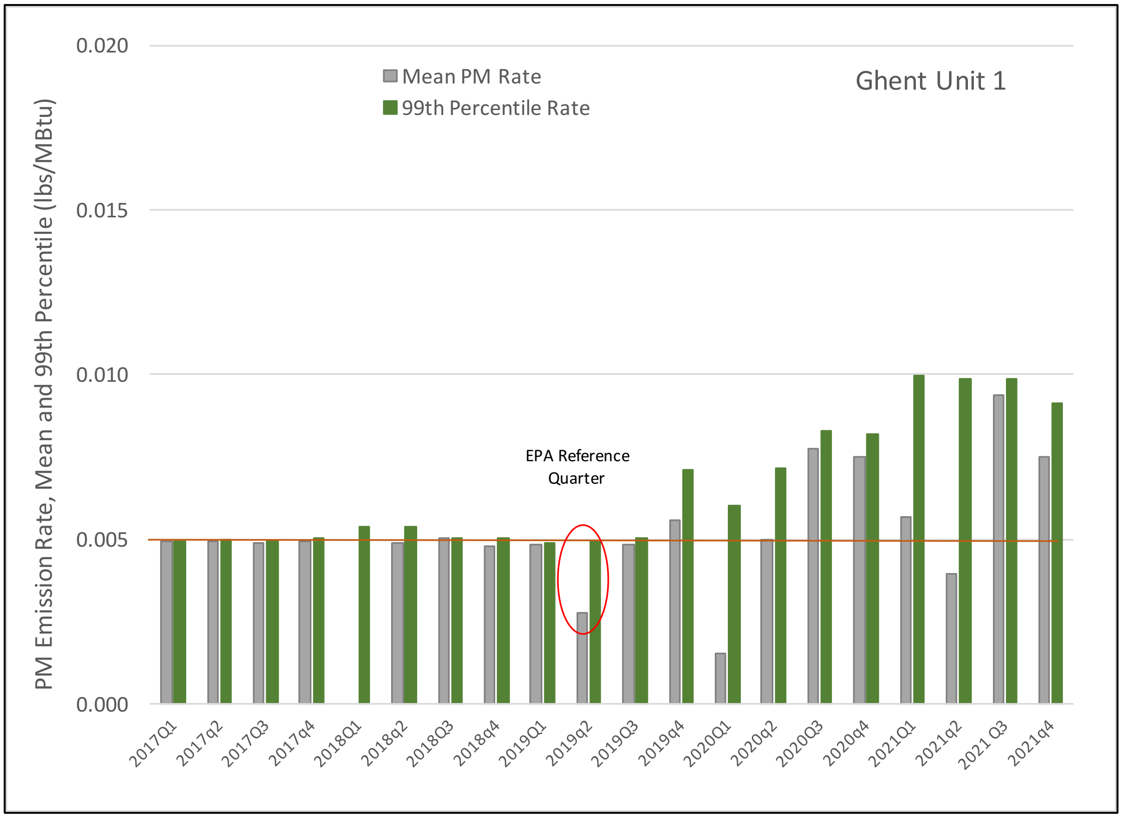
0.010
0.008
0.006
0.004
0.002
0.000
EPA Reference Quarter
18 Q1 18 Q2 18 Q3 1 Q4 19 Q1 19 Q2 19 Q3 19 Q4 20 Q1 20 Q2 20 Q3 20 Q4 21 Q1 21 Q2 21 Q3 21 Q4
2018
2019
2020
2021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0.010
0.005
0.000
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
Mean PM Rate
99th Percentile Rate
Ghent Unit 1
EPA Reference
Quarter
2017Q1
2017q2
2017Q3
2017q4
2018Q1
2018q2
2018Q3
2018q4
2019Q1
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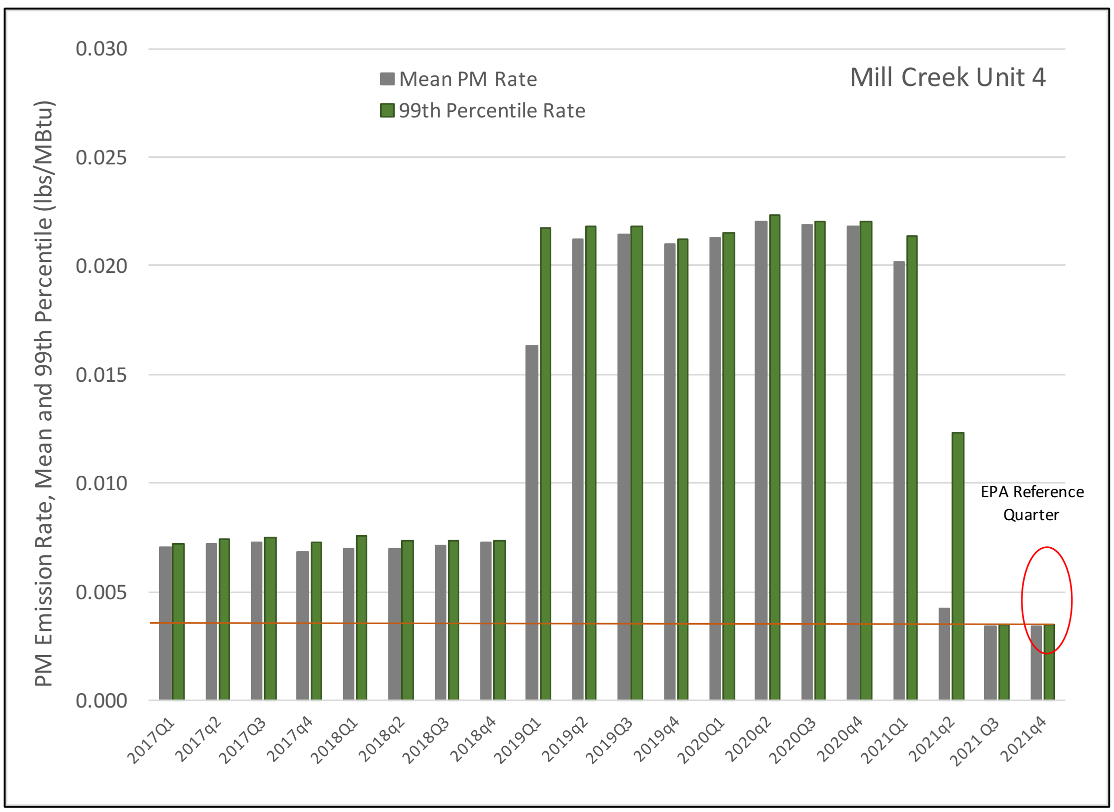
2021 Q3
2021q4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0.025
0.020
0.015
0.010
0.005
0.000
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
Mean PM Rate
99th Percentile Rate
Mill Creek Unit 4
EPA Reference
Quarter
2017Q1
2017q2
2017Q3
2017q4
2018Q1
2018q2
2018Q3
2018q4
2019Q1
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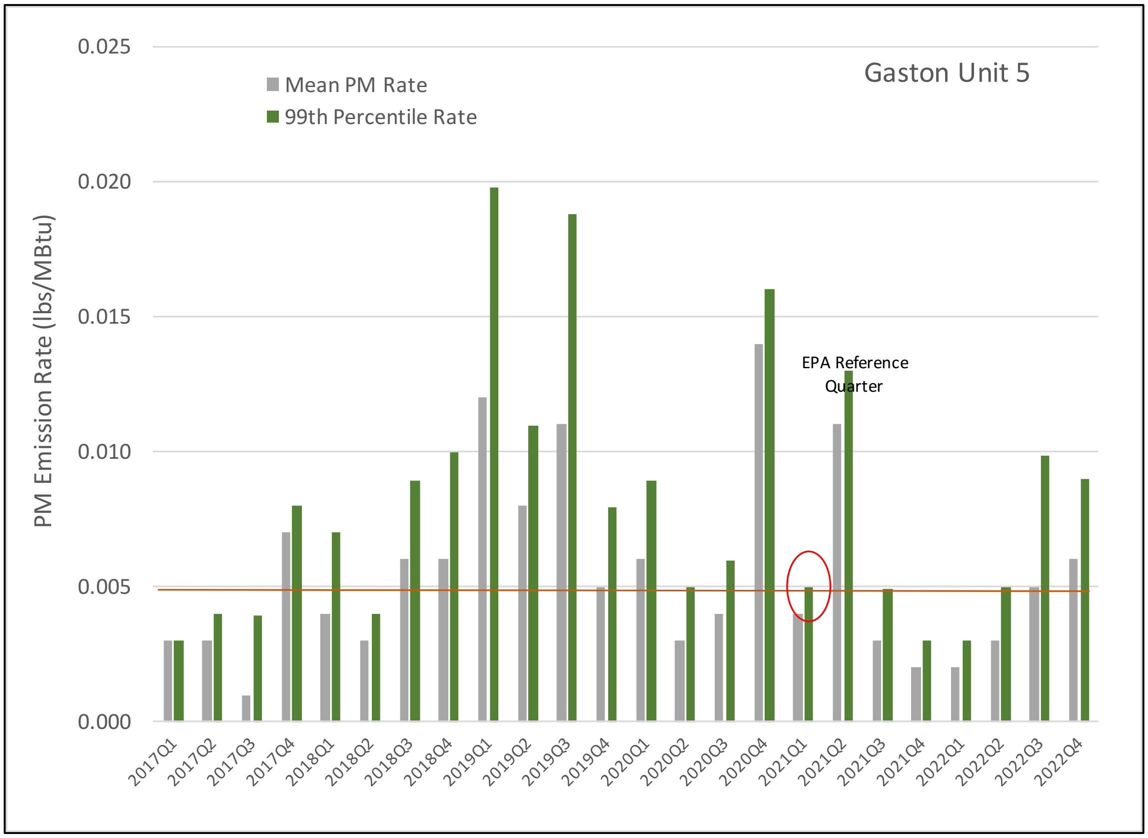
2021 Q3
2021q4



0.025
0.020
0.015
0.010
0.005
0.000
Mean PM Rate
99th Percentile Rate
Gaston Unit 5
PM Emission Rate (lbs/MBtu)
EPA Reference Quarter
2017Q1
2017Q2
2017Q3
2017Q4
2018Q1
2018Q2
2018Q3
2018Q4
2019Q1
2019Q2
2019Q3
2019Q4
2020Q1
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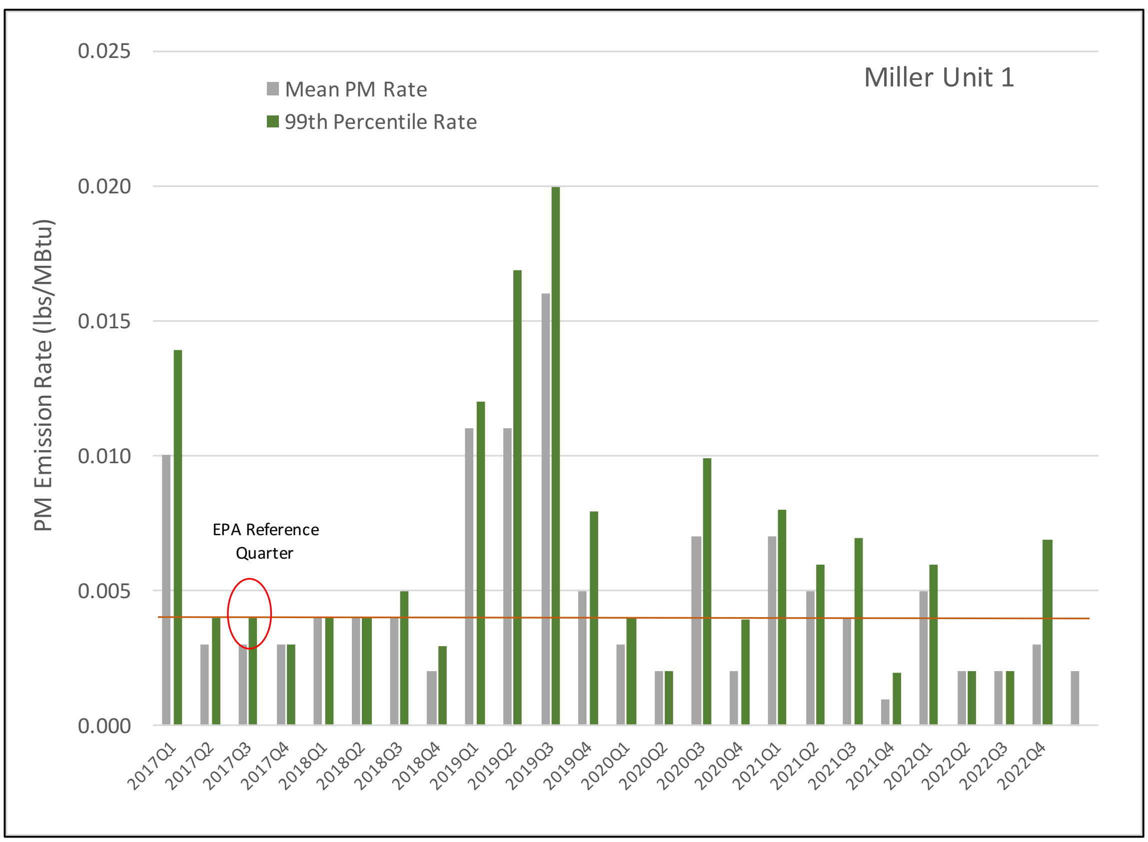
2022Q3
2022Q4

0.025
0.020
0.015
0.010
0.005
0.000
Mean PM Rate
99th Percentile Rate
Miller Unit 1
PM Emission Rate (lbs/MBtu)
EPA Reference Quarter
2017Q1
2017Q2
2017Q3
2017Q4
2018Q1
2018Q2
2018Q3
2018Q4
2019Q1
2019Q2
2019Q3
2019Q4
2020Q1
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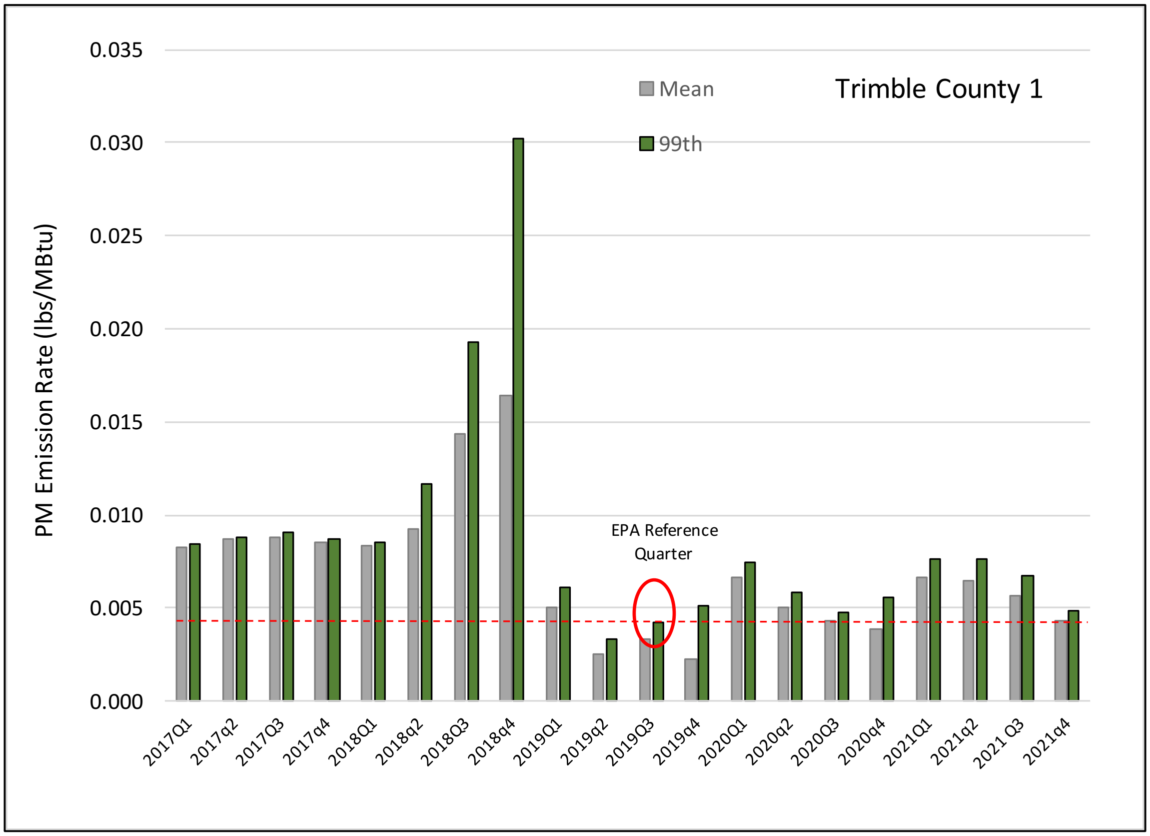
2022Q3
2022Q4


Trimble County 1
Mean
99th
PM Emission Rate (lbs/MBtu)
0.035
0.030
0.025
0.020
0.015
0.010
0.005
0.000
EPA Reference Quarter
2017Q1
2017q2
2017Q3
2017q4
2018Q1
2018q2
2018Q3
2018q4
2019Q1
2019q2
2019Q3
2019q4
2020Q1
2020q2
2020Q3
2020q4
2021Q1
2021q2
2021 Q3
2021q4

# APPENDIX B

Technical Comments on
National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology
Particulate Monitoring Technical Report

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*Prepared for the*

American Public Power Association

June 22, 2023

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On April 24, 2023 the Environmental Protection Agency ("EPA") published in the Federal Register proposed changes to the Mercury Air Toxics Standard ("MATS Rule")[1]. Under the proposed rule, filterable particulate matter ("fPM" or "PM") emission limits would be reduced and the use of PM continuous emissions monitoring systems ("PM CEMS") would be required for all existing electric generating units ("EGUs").

EPA proposes that the use of PM CEMS including sampling times of 3 hours per run is an appropriate approach to minimize uncertainty and cost associated with measurements used to demonstrate compliance with emissions limitations. Not only does the use of PM CEMS not reflect a development in practices, processes, and control technologies that have occurred since the standards were promulgated, but EPAs justification is rife with inconsistencies and inaccuracies. As it did in the initial MATS Rule, EPA claims that the annual cost of quarterly stack testing ("QST") exceeds the cost of PM CEMS. The fallacy of this statement is clearly demonstrated by the fact that PM CEMS are used for compliance purposes by only about one-third of EGU sources subject to the MATS Rule. EPAs assertion that EGU owners opted not to choose the most cost-effective means of demonstrating compliance with the fPM emission limits is not based in fact. Rather, EPA's PM CEMS and associated stack testing cost estimates are inaccurate and do not consider important fiscal and environmental costs associated with a PM CEMS installation, operation, and ongoing requirements.

The cost estimates used by EPA are important because use of PM CEMS does not reflect any improvement in the performance of a unit or any reduction in air pollution. There can be no cost/ton benefit assigned to PM CEMS because it is a measurement technique, not an emission improvement. EPA states that "*PM CEMS provide regulators and the public, as well as the EGU owners or operators, direct and continuous measurement of the pollutant of concern*." However, the pollutant of concern in the context of the MATS rule is non-mercury metal hazardous air pollutants ("HAPS"), not filterable particulate matter. Filterable particulate is a surrogate for non-mercury metal HAPS, not a HAP itself. In addition, commercially available PM CEMS do not even measure filterable particulate matter. PM CEMS measure light scatter or beta-attenuation which is an indicator of filterable particulate matter but is not a *direct* measurement of filterable PM and is certainly not a *direct* measurement of non-mercury metal HAPS . This *indirect* measurement of a *surrogate for the pollutant of concern* includes many ancillary costs that have not only financial implications but also operational and environmental implications.

[1] 88 Fed. Reg. 24854 (Apr. 24, 2023).

## 1. PM CEMS One Time Cost

***EPA underestimated the one-time cost of a PM CEMS. EPA incorrectly excluded Beta attenuation-type PM CEMS from its analysis. PM CEMS should continue to be a monitoring option but should not be required for all existing sources. The additional cost of PM CEMS is not justified as it reflects no improvement in performance, nor does it achieve any emission reductions.***

Table 4 "Non Beta Gauge PM CEMS Estimates Using M5I for PS 11"[2] ("Preamble Table 4") underestimates the costs of PM CEMS. EPA also incorrectly states[3] that beta gauge PM CEMS manufacturing has ceased[4]. Quotes received by PM CEMS vendors and integrators, which includes capital costs associated with the actual instrument, installation (i.e., site preparation and engineering activities), and integration are presented in the "This Study" rows of Table 1 which has been modified from Preamble Table 4. Where vendors provided more than one option for the same make and model, an average of the two instrument costs was used in Table 1[5]. EGU owners and operators for one-time costs,

It appears that the ICAC and Envea/Altech estimates provided by EPA in Preamble Table 4 include only the instrumentation itself without including other installation costs such as  planning and engineering, port installation (approximately $15,000), any enhancements to monitor platform, air and power requirements, or integration with the facility data acquisition and handling system. The exclusion of these costs is the sole reason for EPAs statement that there has been a reduction in current one-time costs for PM CEMS[6].

The proposal states that initial costs in Preamble Table 4 includes emission testing required for initial correlation of the PM CEMS. There is no indication that these costs have been included in the one-time costs for ICAC or Envea/Altech line items of Preamble Table 4[7].

EPA estimates that the cost for conducting PM CEMS correlation testing using EPA Method 5I including 18 runs of 3-hour duration spread over 9 total days to be $58,000,

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[2] 88 FR 24872 (Apr. 24, 2023).
[3] 88 FR 24872 (Apr. 24, 2023).
[4] Beta Gauge instruments represent 12% of the current PM CEMS used by EGUs as reported in the ECMPS electronic monitoring plans. Beta Gauge instruments are currently available for purchase and should be included in the PM CEMS cost estimates.
[5] For example, some manufacturers provided a cost for a base model as well as a cost for installation with a Hastelloy probe. MSI provided two cost estimates, one freestanding and one with shelter installation. In these cases, the average of the available options was used as the initial cost of the instrumentation.
[6] 88 FR 24872 (Apr. 24, 2023).
[7] Since the average one-time costs listed in Table 4 for ICAC and Envea/Altech line items is $57,095 it is impossible that the cost estimate includes the instrument, installation, other initial costs <u>and</u> correlation testing.

and the cost of conducting the same test runs using Method 5 to be $41,000. Stack testing vendors estimate the cost to conduct a PM CEMS correlation using 3-hour duration Method 5 test runs to be $75,000[8]. In addition, EPA apparently did not consider specialized technical support (typically in the form of experienced site personnel or specialized consultants) for correlation testing at an estimated cost of $20,000 per test or site planning and supervision at an estimated cost of $19,500[9]. EPA one-time cost estimates also did not consider additional costs associated with PM spiking, control device detuning, or other research-based approaches for correlating PM CEMS (as discussed further in Section 3.2). The other initial costs in the “This Study” rows of Table 1 include the cost of specialized technical support, site planning and supervision, and costs associated with PM spiking where specified.

The one-time costs presented in Table 1 are a more accurate representation of one time costs associated with PM CEMS installation than provided in Preamble Table 4. However, site-specific factors cannot be ignored. EGUs have reported a wide range of initial costs. One company that installed 19 Envea/Altech PM CEMS between 2012-2015 reports a range of costs between $242,000 - $819,000 per stack. Those costs are considered to include a variety of site-specific factors and include engineering, drawing updates, installing new sample ports, addressing electrical and communication needs, and performing testing. The installations did not require installation of new platforms or any platform modifications. The base price of the Envea/Altech extractive PM CEMS decreased by approximately 16% since 2012. Of course, the cost of skilled labor and trade workers did not decrease during the same time period. A source currently considering installation of an extractive PM CEMS estimates the cost (in current dollars) to be $500,000 without considering testing costs. The costs provided in Table 1 are a more accurate estimate of one time costs but still likely under-estimate the total one-time costs for EGUs.

[8] The incremental cost of performing Method 5I tests instead of Method 5 was not included in this study.
[9] Estimated site coordination before, during, and after correlation testing is 150 hours at $130/hour.

***Table 1 –*** One-time Costs of PM CEMS – Preamble Table 4 and This Study

| Data Source | PM CEMS type | One time costs, $ | | Total Initial Costs |
|---|---|---|---|---|
| | | Instrument and installation | Other initial costs | |
| EPA MCAT | In situ | $ 119,295 | $ 81,229 | $ 200,524 |
| | Extractive | $ 152,850 | $ 81,229 | $ 234,079 |
| EPA CEMS Cost Model | In situ | $ 65,107 | $ 79,813 | $ 144,920 |
| | Extractive | $ 100,427 | $ 84,458 | $ 184,885 |
| Average | - | $ 109,420 | $ 81,682 | $ 191,102 |
| ICAC | Low | $ 35,000 | $ - | $ 35,000 |
| | High | $ 40,000 | $ - | $ 40,000 |
| Envea/Altech | Dry | $ 34,743 | $ - | $ 34,743 |
| | Wet | $ 118,585 | $ - | $ 118,585 |
| Average | - | $ 57,095 | $ - | $ 57,095 |
| ***This Study*** | | | | |
| Sick FWE200DH | Extractive | $ 133,000 | $ 114,500 | $ 247,500 |
| | | $ 133,000 | $ 164,500 * | $ 297,500 |
| Sick SP100 | In-Situ | $ 63,000 | $ 114,500 | $ 177,500 |
| | | $ 63,000 | $ 164,500 * | $ 227,500 |
| PCME 181WS | Extractive | $ 146,600 | $ 114,500 | $ 261,100 |
| | | $ 146,600 | $ 164,500 * | $ 311,100 |
| PCME 181 | In-Situ | $ 80,100 | $ 114,500 | $ 194,600 |
| | | $ 80,100 | $ 164,500 * | $ 244,600 |
| TML LaserHawk 360 | In-Situ | $ 60,000 | $ 114,500 | $ 174,500 |
| | | $ 60,000 | $ 164,500 * | $ 224,500 |
| BetaGuard 3.0 | Extractive | $ 209,000 | $ 114,500 | $ 323,500 |
| | | $ 209,000 | $ 164,500 * | $ 373,500 |
| Average | - | $ 115,283 | $ 139,500 | $ 254,783 |

*Other initial costs include PM spiking by ash injection during initial correlation, where indicated.

## 2. PM CEMS Availability

***The proposal requires the installation of PM CEMS for all existing EGUs. Based on EPA's database only one third of EGUs were using PM CEMS in 2019. There are 223 units that rely on either quarterly or triennial stack testing in the EPA's 2019 database without pre-2027 retirement plans. The planning, purchasing and installation of over 200 PM CEMS concurrently with the replacement of existing***

***PM CEMS will strain equipment vendors, integrators, and stack testers' ability to meet the demand of this proposal.***

The preamble states that one third of existing EGUs are currently using PM CEMS with two thirds utilizing other options under the existing MATS Rule including quarterly stack testing ("QST") for PM, triennial Low-emitting EGU testing ("LEE") for PM, continuous parametric monitoring systems ("CPMS") for PM, or quarterly stack testing for non-Hg metals. Table 2 below provides a summary of EPAs 2017 database[10] of compliance methodologies, 2019 database of compliance methodologies, and the 2027 database of compliance methodologies for remaining units. RTP adjusted EPAs 2019 database for known retirements to occur before 2027, fuel conversions, and excluding records not found in WebFire. Requiring the installation of PM CEMS for all existing EGUs is a significant effort for the EGU fleet, integrators, and instrument suppliers.

***Table 2 –*** Selected Method of Compliance with non-Hg Metals Emission Limitation or filterable PM Emission Limitation

| | **2017** | | **2019** | | **2027 (2019 adjusted )** | |
|---|---|---|---|---|---|---|
| PM CPMS<br>- 30-day rolling average | 10 | 2% | 8 | 2% | 8 | 2% |
| PM CEMS<br>- 30-day rolling average | 205 | 36% | 177 | 36% | 111 | 34% |
| PM Stack Test<br>- 3rd quarter stack test | 250 | 44% | 107 | 22% | 69 | 21% |
| PM LEED<br>- 3rd quarter stack test | 102 | 18% | 195 | 40% | 138 | 42% |
| Non-Hg Metals<br>- 3rd quarter stack test | 6 | 1% | 6 | 1% | 0 | 0% |
| **Total Represented** | **573** | | **493** | | **326** | |
| **Total non-PM CEMS Methods** | **368** | **64%** | **316** | **64%** | **215** | **66%** |

We are currently aware of four primary vendors providing PM CEMS to EGUs. The PM CEMS by vendor presented in Figure 1 is based on ECMPS monitoring plans submitted to EPA during the fourth quarter 2022. One source in the database reported the use of Thermo PM CEMS but at present, Thermo has discontinued sale of its PM CEMS. In the Webfire database, a single Durag PM CEMS was reported, but since the ECMPS monitoring plan did not include its use, it was not included in the figure below.

[10] EPA-HQ-OAR-2018-0794-5561

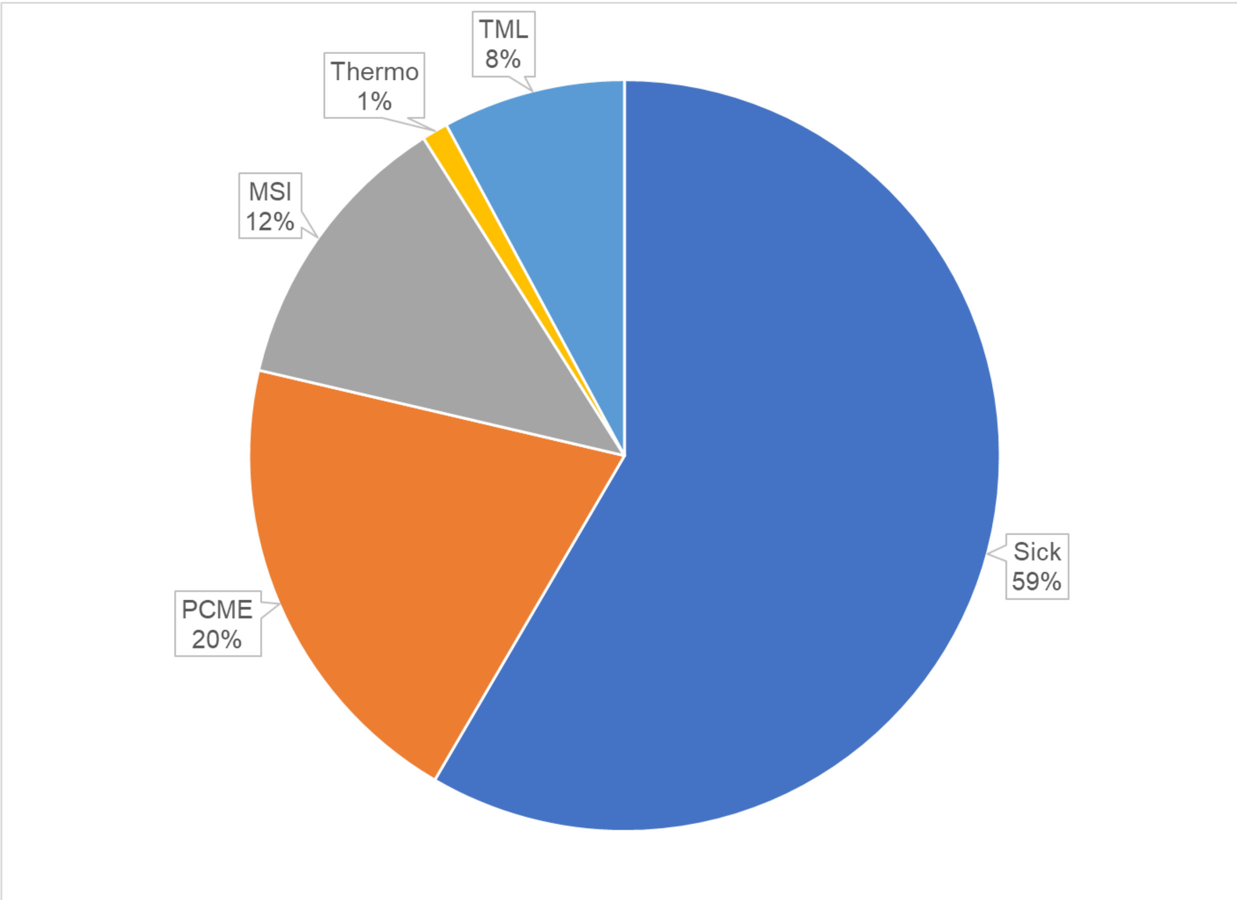


***Figure 1 –*** PM CEMS BY VENDOR (4th quarter 2022 ECMPS Monitoring Plans)

The PM CEMS by vendor presented in Figure 2 is segregated based on in-situ and extractive PM CEMS using data submitted in ECMPS monitoring plans during the fourth quarter 2022. We anticipate that a large number of PM CEMS installations will require extractive systems due to installation on units with add-on pollution controls. Only three models are currently available for use in a wet stack environment[11]. The availability of only three models will complicate industry's ability to install PM CEMS within 3 years after publication of the final rule. In addition, Sick, the vendor with the largest market-share of PM CEMS both overall and for extractive as PM CEMS will no longer service or support its FWE 200 model effective September 1, 2027. Sick has already discontinued sale of its FWE 200 model and has replaced it with the FWE 200 DH model. The existing FWE 200 models in service will be replaced over the next four years. Replacement of existing PM CEMS concurrently with installation of a large number of new PM CEMS will strain equipment vendors, integrators, and stack testers' ability to meet the demand of this proposal.

[11] In the preamble, EPA state that the manufacturing of beta gauge PM CEMS has ceased, but that is not accurate based on email correspondence with MSI, the Beta Guard 3.0 manufacturer.

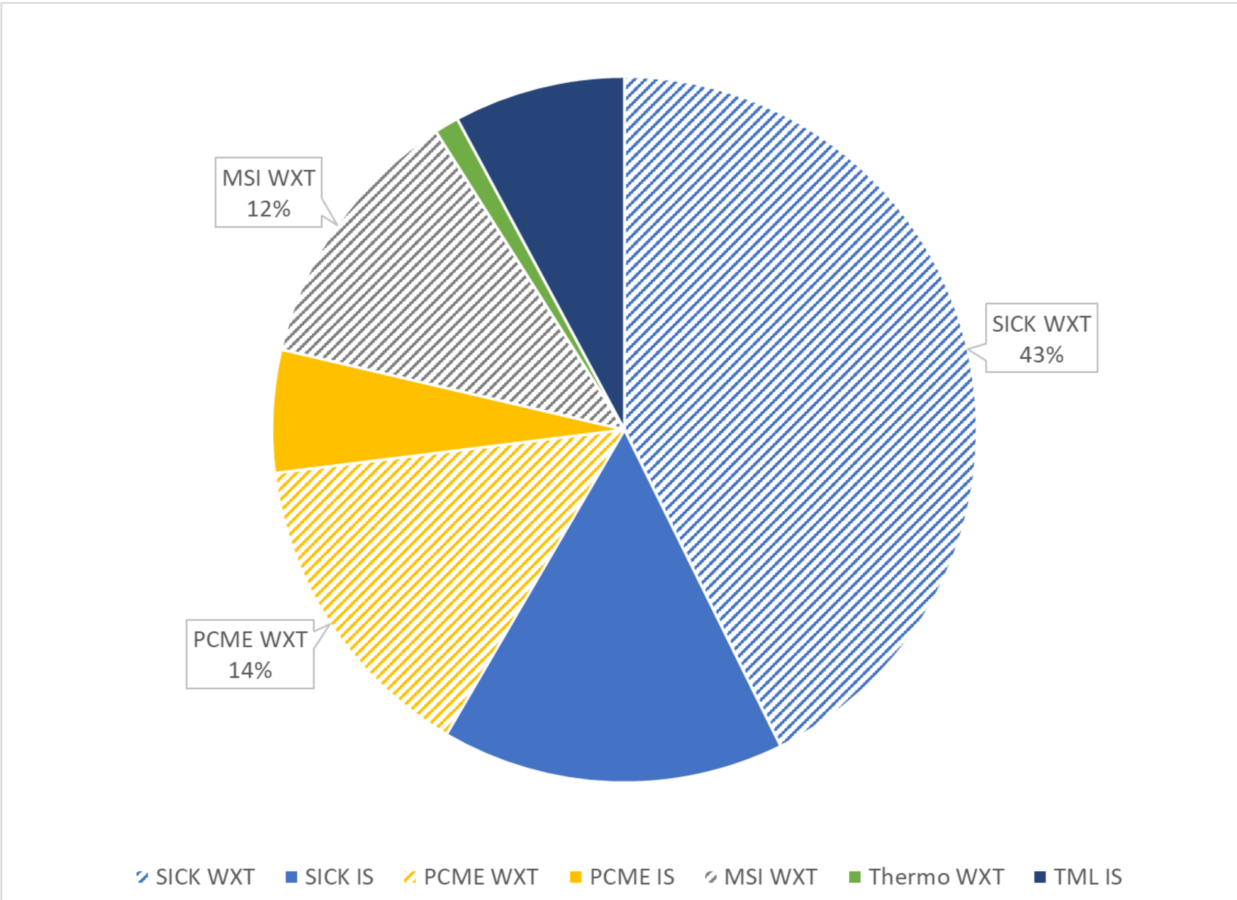


***Figure 2 –*** EXTRACTIVE PM CEMS IN SERVICE (4th quarter 2022 ECMPS Monitoring Plans)

## 2.1 Low-Level Measurement with PM CEMS

***PM CEMS demonstrated limited reliability at emission levels less than 10 mg/acm. EPA should conduct demonstration studies showing that PM CEMS capable of measuring at proposed emission limits prior to establishing such limits and requiring PM CEMS as the sole compliance option.***

Many PM CEMS vendors identify a PM CEMS detection limit of <1 mg/m$^3$, but that detection is meaningless until it is correlated to reference method data during the PS-11 correlation test. EPA attempts to remedy this situation by requiring increased sampling volume to ensure collection of more mass at low emission levels[12] but neglects to address the response of the PM CEMS to variations in particulate matter type. One can assess the relative deviation of individual reference method tests (See Section 3.3) but it is important to also consider if PM CEMS response is varying as expected in response to small changes in fPM concentration. Few correlation tests have been done in the

[12] The proposed rule actually requires collection of more mass at all emission levels while stating concerns with quantification limits which would only impact low-level emissions.

range of 0-10 mg/acm. RTP is aware of less than five PM CEMS that are currently being used to comply with an equivalent emission limit less than 10 mg/acm.

A review of correlations, RRAs and RCAs for existing PM CEMS demonstrates a high degree of scatter at low levels. Figure 3 shows an example of an EGU that is equipped with a baghouse and wet scrubber. The PM CEMS exhibits minimal resolution at low levels (<10 mg/acm). Variability in the y-axis may be partially addressed by increases in sample volume, however, even tests in excess of 3mg (See section 3.3) showed no discernible change in PM CEMS response. In comparison, the same analyzer type installed on a unit with a dry scrubber as shown in Figure 4 demonstrated discernable low level resolution. Low level measurements are particularly challenging in wet stack applications.

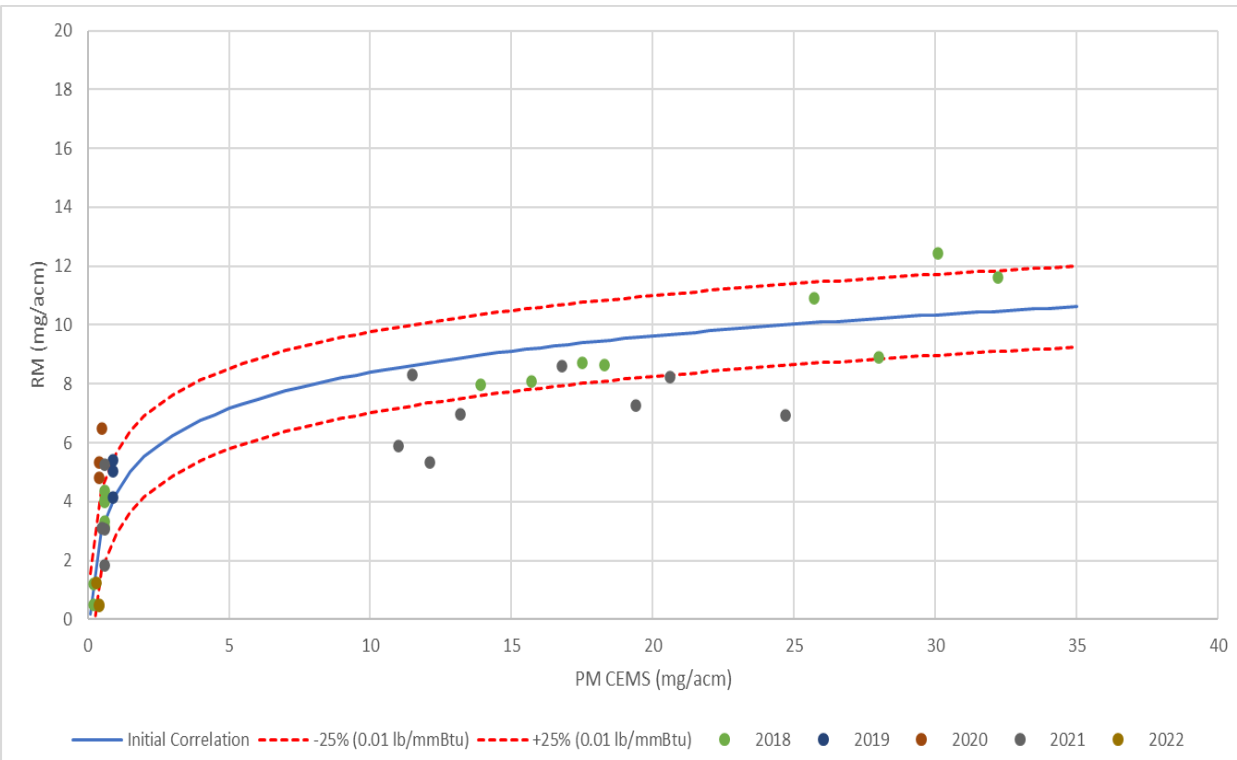


***Figure 3 –*** Example of Low-Level Correlation and QA tests (Baghouse and Wet Scrubber)

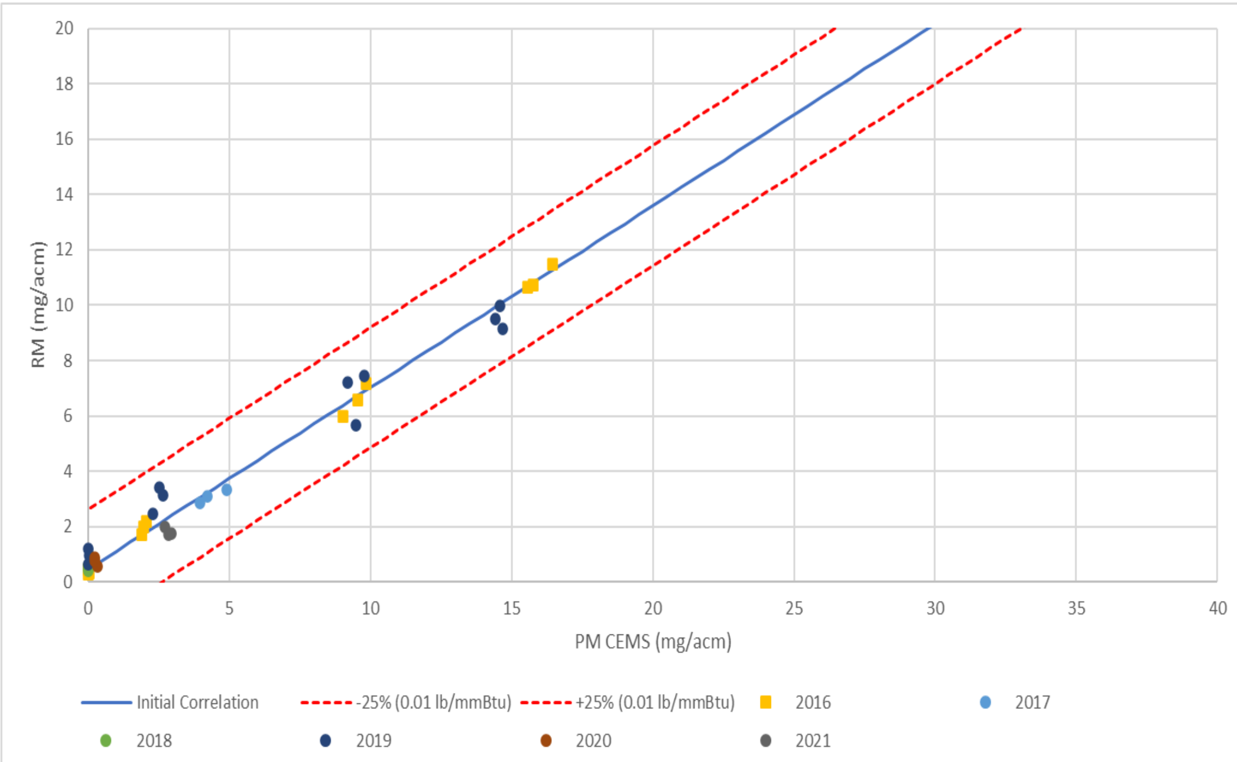


***Figure 4 –*** Example of Low-Level Correlation and QA tests (Baghouse and Dry Scrubber)

### 3. PM CEMS Annual Costs

***EPA under-estimated the annual cost of a PM CEMS. EPA incorrectly excluded Beta attenuation-type PM CEMS from its analysis. PM CEMS should continue to be a monitoring option but should not be required for all existing sources. The additional cost of PM CEMS is not justified as it reflects no improvement in performance, nor does it achieve any emission reductions.***

EPA underestimates annual PM CEMS costs. Quotes received by EGU owners/operators and stack testers for annual costs, which includes capital recovery, operation and maintenance, audits, and other annual costs are presented in the This Study rows of Table 3 which has been modified from Table 4 of the Preamble.

EPA underestimates the annual audit costs associated with PM CEMS. The QA requirements for PM CEMS are addressed in the MATS Rule Appendix C which refers to 40 CFR Part 60, Appendix F, Procedure 2 (“Procedure 2”) and 40 CFR Part 60, Appendix B, Performance Specification 11 (“PS-11”). The QA tests include a relative response audit (“RRA”) once every four calendar quarters and a response correlation audit (“RCA”) once every twelve calendar quarters. In some cases, PM Spiking is required as part of PS-11 correlations or RCAs. According to the preamble EPA included a cost of PM spiking ($35,000) once every 3 years.

Current estimates provided by EGU owners and stack testers are provided in the “This Study” rows of Table 3. The cost of conducting RRAs is equivalent to the cost of a single filterable PM quarterly test or triennial LEE test for PM ($13,000 in testing costs and $1,300 in site-technical support and planning). The cost of conducting RCAs is much greater since it must incorporate additional test runs ($65,000 in testing costs and $10, 400 in site-technical support and planning), careful oversite including specialized technical support ($20,000), and control device detuning and/or PM spiking ($50,000)[13]. As discussed in section 3.1 of this document, we anticipate an increase in the frequency of RCAs if the fPM emission limitation is reduced. In the “This Study” rows of Table 3, it was assumed that an RCA would be required every other year based on the results of the study presented in Section 3.1. The cost of that PM spiking provided by EGU owners was higher than what was used by EPA[14]. The annual audit costs in the “This Study” rows of Table 3 have been calculated based on the increased frequency of RCAs as discussed in Section 3.1, the increased cost associated with PM spiking discussed in Section 3.2 and the proposed increase in PM test run sample volume/duration as discussed in Section 3.3.

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[13] One EGU owner estimated $250,000 for RCAs that include PM spiking, reference method testing costs with on-site analysis, and technical support for executing the test program. They highlight that the testing expenses and PM spiking costs are a fraction of the overall planning and coordination that goes into such a testing event.

[14] The PM spiking costs provided assumes injection of site-produced flyash. The incremental cost associated with purchase of surrogate fPM for injection (as opposed to flyash) was not included in this study. Surrogate fPM may be used due to material handling issues with injection of flyash. Surrogate fPM, such as carbon or silica materials have the added advantage of not emitting additional HAPS for the sole purpose of correlation testing. The purchase of surrogate materials is approximately $15,000 per unit according to one EGU owner. Use of surrogate materials for correlation may not be as representative of actual upset conditions based on changes in the PM characteristics (i.e., size, color and/or shape, or beta attenuation).

***Table 3 –*** Annual Costs of PM CEMS – Preamble Table 4 and This Study

| Data Source | PM CEMS type | Annual costs, $ | | | | EUAC, $ |
|---|---|---|---|---|---|---|
| | | **Capital recovery** | **Operation and maint.** | **Audits** | **Other annual costs** | |
| EPA MCAT | In situ | $ 22,016 | $ 1,558 | $ 54,877 | $ 11,219 | $ 89,670 |
| | Extractive | $ 25,700 | $ 2,579 | $ 54,877 | $ 12,241 | $ 95,397 |
| EPA CEMS Cost Model | In situ | $ 15,912 | $ 2,689 | $ 54,392 | $ 6,525 | $ 79,518 |
| | Extractive | $ 20,300 | $ 3,689 | $ 54,392 | $ 7,525 | $ 85,906 |
| Average | - | $ 20,982 | $ 2,629 | $ 54,635 | $ 9,378 | $ 87,623 |
| ICAC | Low | $ 3,843 | $ 12,000 | $ 14,290 | $ - | $ 30,133 |
| | High | $ 4,392 | $ 12,000 | $ 14,290 | $ - | $ 30,682 |
| Envea/ Altech | Dry | $ 3,821 | $ - | $ 14,290 | $ - | $ 18,111 |
| | Wet | $ 13,020 | $ - | $ 14,290 | $ - | $ 27,310 |
| Average | - | $ 6,269 | $ 12,000 | $ 14,290 | $ - | $ 32,559 |
| ***This Study*** | | | | | | |
| Sick FWE200DH | Extractive | $ 27,225 | $ 22,500 | $ 54,850 | | $ 104,575 |
| | | $ 32,725 | $ 22,500 | $ 79,850 * | | $ 135,075 |
| Sick SP100 | In-Situ | $ 19,525 | $ 18,900 | $ 54,850 | | $ 93,275 |
| | | $ 25,025 | $ 18,900 | $ 79,850 * | | $ 123,775 |
| PCME 181WS | Extractive | $ 28,721 | $ 22,500 | $ 54,850 | | $ 106,071 |
| | | $ 34,221 | $ 22,500 | $ 79,850 * | | $ 136,571 |
| PCME 181 | In-Situ | $ 21,406 | $ 18,900 | $ 54,850 | | $ 95,156 |
| | | $ 26,906 | $ 18,900 | $ 79,850 * | | $ 125,656 |
| TML LaserHawk 360 | In-Situ | $ 19,195 | $ 18,900 | $ 54,850 | | $ 92,945 |
| | | $ 24,695 | $ 18,900 | $ 79,850 * | | $ 123,445 |
| BetaGuard 3.0 | Extractive | $ 35,585 | $ 33,700 | $ 54,850 | | $ 124,135 |
| | | $ 41,085 | $ 33,700 | $ 79,850 * | | $ 154,635 |
| Average | - | $ 28,026 | $ 22,567 | $ 67,350 | | $ 117,943 |

*Audit costs include PM spiking by ash injection during RCAs presumed to be necessary every other year.

## 3.1 RCA Frequency

***The frequency of RCAs will increase with a reduction in the emission limitation. The increased frequency of RCAs impacts the cost associated with annual PM CEMS audits and has negative implications on operating equipment and the environment.***

The frequency of RCAs significantly increases the audit costs associated with PM CEMS. Procedure 2 requires that an RCA be conducted if an RRA does not meet the QA specification, and the MATS Rule Appendix C requires that an RCA be conducted at least once every three years even if each RRA meets the specifications. Since the specifications for RRAs and RCAs is expressed as a percentage of the emission limitation, lowering the emission limitation also makes it more difficult to pass each QA test for a PM CEMs. The tolerance for an RRA or RCA is commonly referred to as the "acceptable area" of a graph, or a specified area on a graph of the correlation regression line. This "acceptable area" is shown graphically in Figure 5 and is denoted by dotted lines. As the emission limit decreases, the "acceptable area" compresses making it more difficult to pass each test due to variability in unit operations and variability in adherence to manual stack testing methodologies.

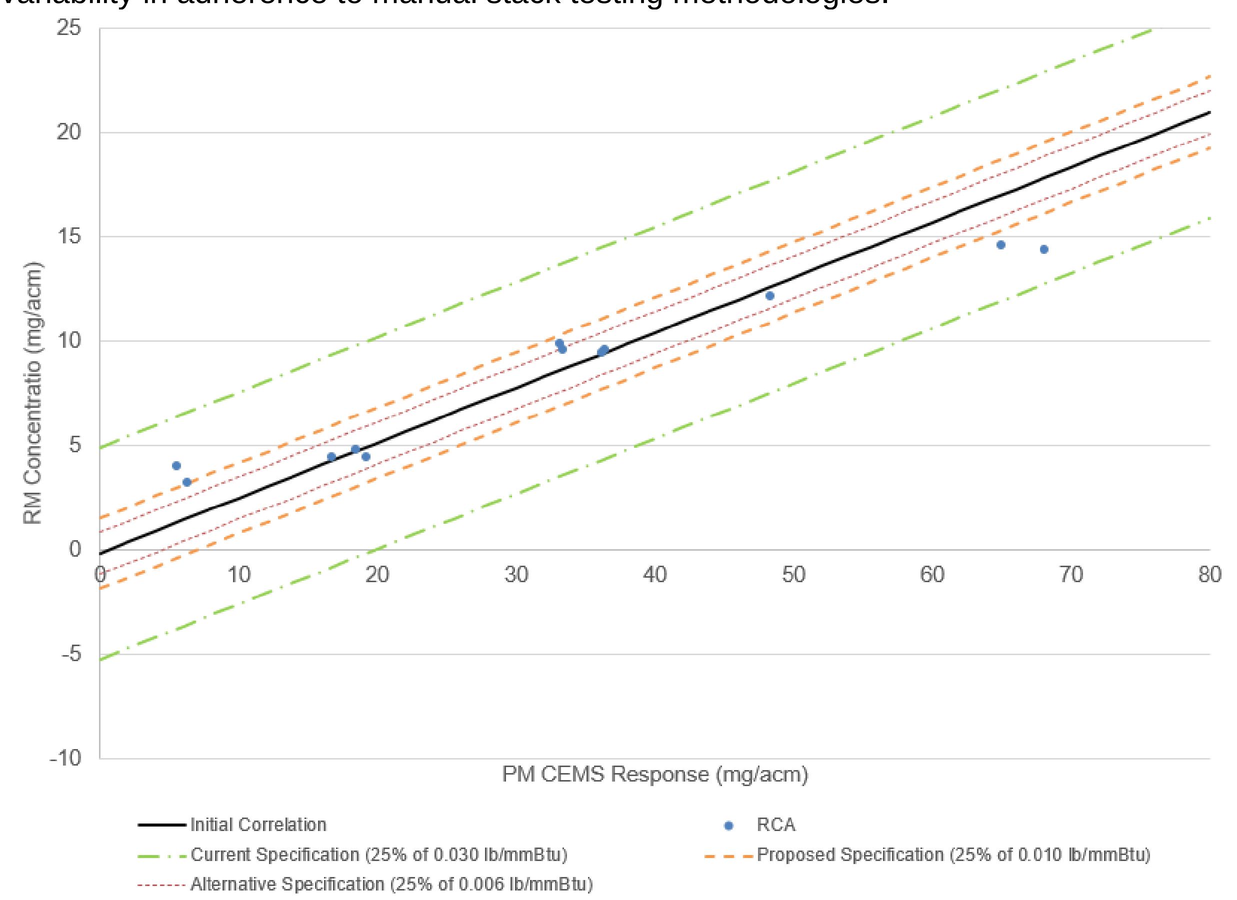


***Figure 5 –*** Example of RCA specifications at varying emission limitations

A blind study of existing EGUs with PM CEMS was conducted to determine the frequency of QA test failures at the current emission limit of 0.030 lb/mmBtu, the proposed emission limit of 0.010 lb/mmBtu and the more stringent regulatory option of 0.006 lb/mmbtu (“alternate limit”)[15]. As shown graphically in Figure 6, 44% of the total number of tests would not be successful using a specified area determined at an emission limitation value equivalent to 0.10 lb/mmBtu and 68% of the total number of tests would not be successful using a specified area determined at an emission limitation value equivalent to 0.006 lb/mmBtu. The results of the study demonstrate that EPAs cost estimates underestimate annual cost since it assumes that it will only be necessary to vary filterable PM once every 3 years. In any given year, nearly half of the tests conducted would not be RRAs (estimated to cost $8,500 and $13,000 for 1 dscm/run and 4 dscm/run, respectively) that require no specialized support or varying of PM concentration, but instead would be the lengthier and more involved RCAs (estimated to cost $22,000 and $65,000 for 1 dscm/run and 4 dscm/run, respectively). RCAs also require specialized technical support at a cost of $20,000-$30,000 per test program and control device detuning or PM spiking at a cost of (approximately $50,000 as discussed further in Section 3.2).

[15] Particulate Matter Continuous Emission Monitoring System Quality Assurance Test Evaluation. EPRI, Palo Alto, CA: 2022. 3002027695.

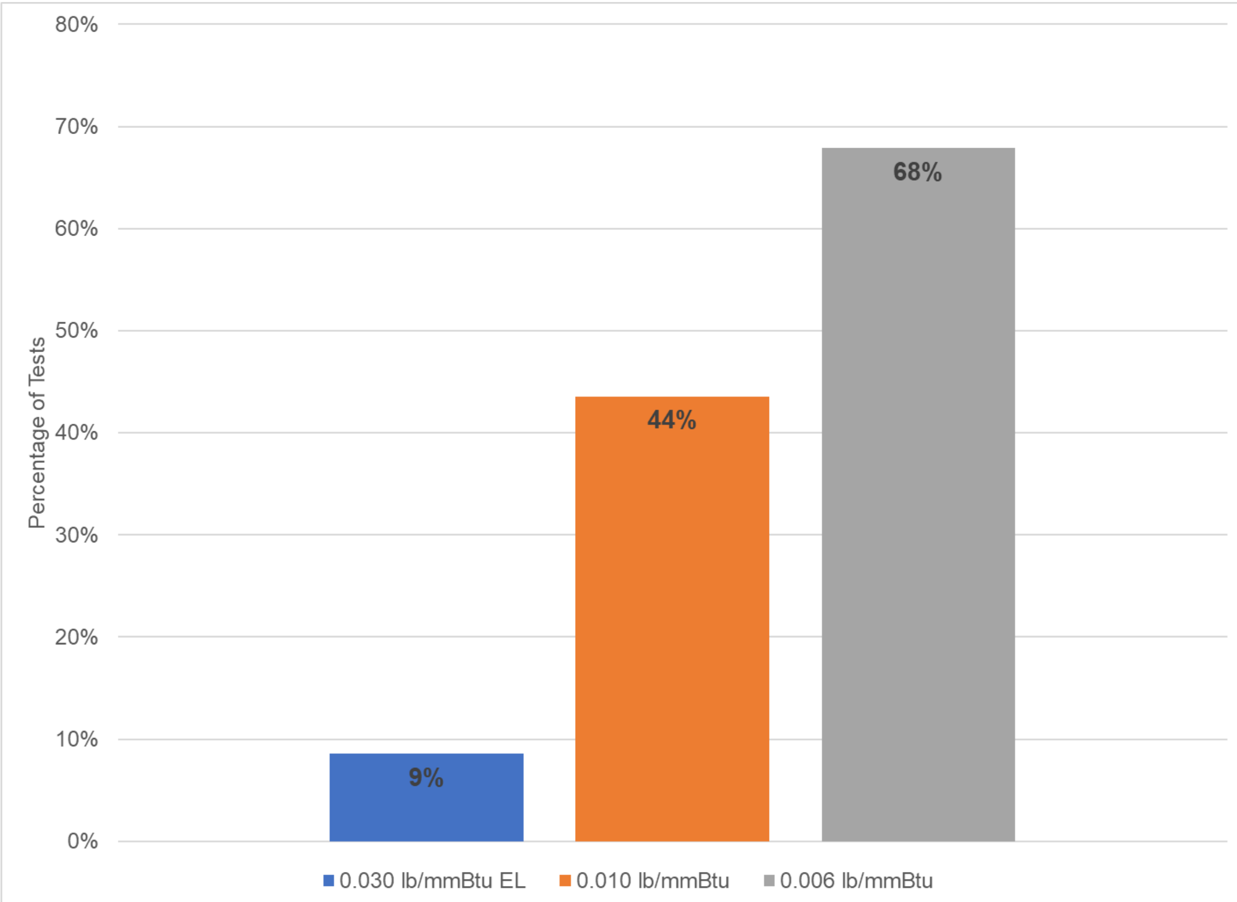


***Figure 6 –*** QA Test Failure Rate by Emission Limit

The preamble indicates that "not every EGU will need to adjust its existing correlation in order to continue to use its existing PM CEMS to demonstrate compliance with the proposed limits"[16]. Unless EPA proposes or states otherwise, any existing correlation curve will be required to, at a minimum, re-evaluate the PM CEMS correlation curve using the lower equivalent emission limit. As shown in Figure 6, it is likely that RCA specifications will not be met at the lower equivalent emission limit and adjustment of the correlation will be required. In addition, any new correlations developed must meet PS-11's correlation statistical criteria, which are also expressed as a percentage of the emission limit.

RTP evaluated correlation tests for selected candidate units. Seventeen individual tests were evaluated. The data show that only five (29%) of the units can meet the PS-11 statistical criteria with the proposed limit of 0.010 lb/MMBtu and only one unit (6%) meets the criteria with the alternate limit of 0.006 lb/MMBtu.  These data suggest that most units would need to adjust the correlation of the PM CEMS regardless of the

[16] 88 FR 24874 (Apr. 24, 2023).

proposed limit. These costs impact not only sources that don't currently have PM CEMS, but all existing sources.

### 3.2 Varying PM Concentration for Correlation Testing and RCAs

***Varying of PM concentration, as required for PM CEMS correlations and RCAs is costly, not consistently representative of true upset conditions, and has negative implications on operating equipment and the environment.***

For PS-11 initial correlations and RCAs, it is necessary to vary PM concentration level. Varying PM concentration intentionally is a costly process from an operational standpoint as well as an environmental standpoint. Varying PM concentration levels is typically conducted by detuning of control equipment, injection of ash, injection of an ash surrogate, or the use of research-based techniques.

Detuning of control devices is a complicated process that involves intentionally disabling control devices for the sole purpose of generating emissions. Since the air emission control systems work together and are not designed for extended operation under abnormal conditions, detuning of control devices requires careful consideration of downstream impacts. For example, an EGU that is equipped with an electrostatic precipitator (ESP) and wet flue gas desulfurization (wet FGD) may find it necessary to intentionally turn off multiple fields of its ESP in order to achieve an increase in particulate matter. However, because the unit is also equipped with a wet FGD it may also be necessary to reduce slurry injection to negate any filterable PM reduction in the wet FGD. Others may increase slurry injection to allow more scrubber carry-over. These approaches have the desired effect of varying the filterable particulate emissions in the stack but are rarely representative of actual control device upsets. A unit equipped with a baghouse may detune by removing individual bags from the baghouse to simulate failure or may install a slip stream baghouse bypass.

The detuning approaches must be carefully selected to be representative of actual control device upset conditions, sustainable for the duration of the test runs at the particulate loading level (3 hours per test run is currently proposed), and repeatable for subsequent RCAs[17]. Light-scattering PM CEMS, which make up the majority of the PM CEMS in use (88% of currently installed and operational PM CEMS rely on light-scattering) are more sensitive to changes in the characteristics of particulate (i.e., size, color, shape, reflective index) emitted during these detuning activities.

Ash injection is another method of varying PM concentration levels for the purposes of correlations. PM spiking involves introducing known amounts of filterable particulate matter to the stack without altering the control device operation. The use of ash injection is limited due to cost and practicality. As with control device detuning, ash injection

[17] As an example, on October 3, 2019 ORIS Code 645, Unit ID BB03 was unable to successfully meet the RRA specifications. Upon further review, the source determined that "the existing correlation curve is only representative without the injection and evaporation of recycle water."

involves intentionally increasing particulate matter exiting the environment. The type of particulate matter selected (actual fly ash versus other surrogates) may impact the correlation, especially for PM CEMS using light-scattering technology. Injecting the particulate matter in a manner consistent with normal operation and avoiding stack stratification is a time-consuming and expensive process that requires a high degree of technical support.

Both detuning of control devices and ash injection represent abnormal operating conditions. Because these detuning conditions are abnormal, it is very difficult to achieve steady-state particulate loading for the purposes of conducting multiple EPA Reference Method test runs for the purpose of correlations. Source owners and the public should be hesitant to extend the duration of these abnormal operation conditions because of their downstream impact on other process equipment as well as the environmental impact on the surrounding community. Intentional emissions increases should be minimized wherever possible.

As discussed in the preamble, the Electric Power Research Institute (EPRI) has developed a Quantitative Aerosol Generator (QAG) to allow direct PM CEMS calibration, as opposed to the development of a curve that provides a correlation for the PM CEMS. The QAG has exhibited potential on selected sources using the current MATS filterable particulate matter limit of 0.030 lb/mmBtu. The QAG is not currently an approved test method for correlating PM CEMS and has not been subject to ongoing evaluation since 2019 and as such is referred to as a research-based technique in this document. The tolerance interval and confidence interval for the field study test sites, when determined based on the proposed emission limit of 0.010 lb/mmBtu, do not reflect the same success rate as that determined based on the current emission limit of 0.030 lb/mmBtu. QAG calibration services were estimated at $30,000 in 2019 ($40,200 adjusted). The cost of QAG calibration services is less than that of ash reinjection and has the added benefit of not requiring intentional emissions increases. However, given the limited number of individuals qualified to conduct QAG calibration services, the limited current research at proposed emission limit levels, and lack of “Other Test Method” approval, the QAG cannot be considered commercially available for new PM CEMS installations.

***Table 4 –*** Cost of Varying PM Concentration for Correlation Tests and RCAs

| Test Type | Type | Cost/Test, $ | Notes |
|---|---|---|---|
| EPA Preamble[18] | PM Spiking | $ 35,000 | Cost per test |
| This Study | Flyash Reinjection | $ 50,000 | Cost per test |
| This Study | Surrogate Injection | $ 65,000 | |
| This Study | Control Device Bypass | $ 50,000 | One-time cost of installation |
| This Study | QAG | $ 40,000 | Not commercially available |

Varying PM concentration intentionally is a costly process from an operational standpoint as well as an environmental standpoint. Where PM CEMS are used, the proposed actions below will reduce the impact of the requirement to vary PM concentration:

1. EPA should allow all sources to use zero-point data[19] as a level of the correlation. PS-11 Section 8.6(4)(i) requires that sources "attempt to obtain three different levels of PM mass concentration by varying process operating conditions, varying PM control device operation, or by means of PM spiking." PS-11 Section 8.6(5) allows the use of zero-point data only "of you cannot obtain three distinct levels of PM concentration as described." The use of zero-point data improves the overall correlation and will reduce testing costs and operational burden.
2. EPA should not require three different levels of PM mass concentration for correlations but should grant sources the flexibility to test at normal operational levels and extrapolate beyond the highest point used in the correlation for reporting purposes. PS-11 Section 8.8 requires adjustment of the correlation if a source generates 24 consecutive hourly averages in excess of 125% of the highest value used in the correlation (or 50% of the equivalent emission limit for low-emitting sources) or if 5% of the hourly averages in a 30-day period are in excess of 125% of the highest value used in the correlation (or 50% of the equivalent emission limit for low-emitting sources). If these conditions occur, additional testing must be conducted within 60 days under the conditions that caused the higher PM CEMS response. In evaluating compliance, sources and EPA have relied on quarterly submittal of 30-day averages. A source should be permitted to extrapolate beyond the highest point used in the correlation for

[18] 88 FR 24873 (April 24, 2023)

[19] Zero-point data is a value added to PM CEMS correlation data to represent low or near zero PM concentration data which may be obtained by removing the instrument probe from the stack and monitoring ambient air or by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g, when the process is not operating, but the fans are operating or your source is combusting only natural gas).

reporting purposes and should not have to conduct additional testing unless 5% of the 30-day averages in a reporting quarter are in excess of 125% of the highest value used in the correlation (or 50% of the equivalent emission limit for low-emitting sources). If this condition occurs, the source should be required to conduct additional testing within 720 operating hours after the end of the quarter in which the need is identified. A source should attempt to replicate the conditions that caused the higher PM CEMS response where practicable[20]. Allowing extrapolation of the correlation curve with quarterly evaluation of the extent of extrapolation will reduce testing costs, operational burden, and may allow sources to conduct correlations without requiring significant detuning of control equipment or ash injection solely for the purpose of calibrating instrumentation.

### 3.3 Increase in PM test run sample volume/duration

***The increase in PM test run sample volume/duration in the proposed rule is unnecessary, is costly, not consistent with the duration of true upset conditions, and has negative implications on operating equipment and the environment.***

EPA proposed to increase the minimum sample volume requirement for performing MATS-modified[21] EPA Reference Method 5 from one (1) dry standard cubic meter (dscm) to four (4) dscm. The stated purpose of the increase in sample volume is to reduce the "random error" associated with the measurement to less than 15%. In the supporting documentation[22] , the author does not use the correct filterable particulate matter (fPM) concentration units for describing the equivalent fPM concentration at the various emission limits. In Table 1 of the memorandum titled "PM CEMS Random Error Contribution by Emission Limit", the "Emission Limit" column the unit of measure is listed as milligrams per dry standard cubic meter (mg/dscm), but the concentrations listed are values that are in units of milligrams per wet actual cubic meter (mg/wacm).[23] Table 5 provides the true equivalent fPM concentration in units of mg/dscm.

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[20] It may not be possible to fully replicate control device failure conditions at a later date.

[21] Sample probe and sample filter temperatures maintained at 320 °F (±25 °F).

[22] EPA-HQ-OAR-2018-0794-5786

[23] Actual conditions refer to the temperature and pressure at which the PM CEMS makes the PM concentration measurement. All current commercially available PM CEMS measure PM concentration on a wet-basis.

***Table 5 –*** Summary of fPM Equivalent Emission Limit Concentration

| Emission Limit Descriptor | Emission Limit | Emission Limit Concentration | | Target Compliance Level |
|---|---|---|---|---|
| | (lb/mmBtu) | (mg/wacm) | (mg/dscm) | (mg/dscm) |
| Current | 0.030 | 21.9 | 34.2 | 17.1 |
| New Unit | 0.009 | 6.6 | 10.2 | 5.1 |
| Proposal 1 | 0.010 | 7.3 | 11.4 | 5.7 |
| Proposal 2 | 0.006 | 4.4 | 6.8 | 3.4 |

In addition, the memorandum states that the method detection level (MDL) for EPA Reference Method 5 is 2.0 mg/dscm.[24] The referenced memo does not provide any supporting information on how the MDL was derived and differs significantly from other guidance on the MDL for EPA Reference Method 5. In the January 14, 2019 version of EPA Reference Method 5I, Section 2.3.b provides the following statement on the appropriate MDL for EPA Reference Method 5; "*Because the MDL forms the basis for our guidance on target sampling times, EPA has conducted a systematic laboratory study to define what is the MDL for Method 5 and determined the Method to have a calculated practical quantitation limit (PQL) of 3 mg of PM and an MDL of 1 mg*." This statement in a promulgated reference method that has withstood the rigors of public notice and comment should be the MDL used for any assessment of required sample times or sample volumes for the measurement of fPM.

In a presentation authored by Steffan Johnson, Leader of EPA's Measurement Technology Group titled "Bringing Minimum Detection Levels into Focus"[25], it states that EPA's air test methods at or above the method's limit of quantification (LOQ) have a measurement uncertainty of ±15-20%. Where LOQ in the presentation was defined as three (3) times the MDL and has the same practical definition as PQL given in EPA Reference Method 5I.

Using 1 mg as the MDL for a MATS-modified EPA Reference Method 5 test run and an associated PQL/LOQ of 3 mg, a minimum sample volume of 1 dscm should suffice in demonstrating reliable results at the current proposed fPM emission limits. At the lowest proposed limit of 0.006 lb/mmBtu, a one-hour MATS-Modified EPA Reference Method 5 test run operated at a nominal sample rate of 0.75 dry standard cubic foot per minute (dscfm) would yield a sample volume of ~45 dscf (i.e., 1.27 dscm). At a "desired target concentration" of 3.4 mg/dscm, a one-hour test duration should yield a sample mass of ~4.3 mg. That expected sample mass is ~44% higher than the PQL/LOQ of 3 mg.

Under the current MATS Rule, sources have the option to demonstrate compliance with the 0.030 lb/mmBtu fPM emission limit by performing quarterly stack tests, which

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[24] PM CEMS Capabilities Memo, June 13, 2012, from Conniesue Oldham to Bob Schell, available at EPA-HQOAR-2018-0794.
[25] https://www3.epa.gov/ttnemc01/meetnw/2015/moreado.pdf

require a minimum sample volume of 1 dscm. Sources also have the option to qualify as a low emitting EGU (LEE) by demonstrating that the fPM emissions are less than 50% of the 0.030 lb/mmBtu emission limit (i.e., 0.015 lb/mmBtu), which requires a minimum sample volume of 2 dscm. Table 6 below provides a summary of EPAs 2019 database[26] of compliance methodologies highlighting the impact of sample volume on the variability of the fPM mass emission rate measurement. Both the quarterly tests (presumed to be 1 dscm sample volume) and the LEE tests (presumed to be 2 dscm sample volume) tests were parsed into three (3) subsections representing the current MATS Rule fPM emission limits (i.e., 0.030 lb/mmBtu compliance limit and the 0.015 lb/mmBtu LEE qualification limit), the proposed 0.010 lb/mmBtu compliance limit and the proposed alternative compliance limit of 0.006 lb/mmBtu. A relative standard deviation was calculated based on each available set of three (3) to four (4) test runs using the appropriate emission limit in the denominator rather than the average of the test runs. The data indicate that doubling the sample volume had no significant impact on the overall variability in the fPM emission rate measurement. There is no reason to believe that quadrupling the sample volume, as EPA has proposed, would have any significant impact on the overall variability in the fPM emission rate measurement either.

***Table 6 –*** Effects of LEE Sampling Volume on Measurement Variability

| Emission Level | Quarterly (1 dscm) | | | LEE (2 dscm) | | |
|---|---|---|---|---|---|---|
| | **# of Sets** | **Mean (lb/mmBtu)** | **Mean RSD** | **# of Sets** | **Mean (lb/mmBtu)** | **Mean RSD** |
| ≤0.006 lb/mmBtu | 41 | 0.004 | 13.5% | 134 | 0.005 | 18.0% |
| >0.006 & ≤ 0.010 lb/mmBtu | 14 | 0.008 | 17.9% | 34 | 0.008 | 15.3% |
| >0.010 & ≤ 0.015 lb/mmBtu | 13 | 0.012 | 9.1% | 12 | 0.012 | 14.2% |
| >0.015 lb/mmBtu | 23 | 0.023 | 14.8% | 3 | 0.017 | 11.2% |

3.4 Recommended MATS Appendix C Modifications

***PM CEMS annual costs are significantly higher than the cost of quarterly PM testing or triennial PM LEE testing. Although not included in the scope of the MATS RTR proposal, the proposed actions below will reduce the annual costs and operational burden for sources that are currently using PM CEMS and for those installing and operating PM CEMS in the future.***

1. EPA should modify the MATS Appendix C requirements to state that an RCA is only required if an RRA is unsuccessful. Requiring recurring RCAs when there is no reason to doubt the representativeness of the existing correlation increases

[26] EPA-HQ-OAR-2018-0794-5561

the testing cost, specialized support cost, and detuning or ash injection costs. The detuning of control devices causes operational difficulties (such as increasing solids in scrubber slurry) and environmental implications. The entire PS-11 correlation approach and RCA approach involves intentionally increasing emissions for the sole purpose of calibrating or correlating instrumentation. Intentional emissions increases should be minimized wherever possible.

2. The sample volume and duration of test runs conducted at increased particulate loading should be minimized. Requiring extended test run duration at elevated emission rates causes operational difficulties (such as increasing solids in scrubber slurry), is not representative of actual short term control device failure conditions, and causes intentional pollution solely to calibrate or correlate instrumentation.
3. EPA should modify the MATS Appendix C requirements to allow use of “QA operating quarters” and “Grace Periods” consistent with 40 CFR Part 75, as incorporated into MATS Appendix A and Appendix B but omitted from MATS Appendix C.. As coal-fired EGUs operate less frequently, requirements to conduct quality assurance tests based on a certain number of calendar quarters defeats the purpose of minimizing emissions. Likewise, incorporating a modified version of a grace period that relies on the lesser of 720 EGU (or stack) operating hours or 1 calendar quarter still requires testing during a subsequent calendar quarter regardless of whether the EGU (or stack) would otherwise operate. The use of “QA Operating Quarters” and “Grace Period” provisions of 40 CFR Part 75 allows a source that is infrequently operated to postpone QA testing until such time that the source resumes more frequent operation. These provisions eliminate the need to operate a unit solely for the purpose of testing. EPA should require that a RRA be conducted once every four QA Operating Quarters[27]. If a RRA is not conducted within four QA operating quarters or eight calendar quarters, the RRA shall be conducted within 720 unit (or stack) operating hour grace period following the end of the four QA Operating Quarters or eighth successive elapsed calendar quarter. If EPA retains the requirement to perform periodic RCAs, the use of “QA operating quarters” and “Grace Periods” should also apply to RCAs.

## 4. Quarterly or Triennial Testing Costs

***EPA overestimated the cost of quarterly fPM stack testing. PM CEMS are significantly more expensive than conducting quarterly fPM testing. PM CEMS are also significantly more expensive than conducting testing for individual or total non-Hg metals, which has the added benefit of measuring the actual HAP, not a***

[27] *QA operating quarter* means a calendar quarter in which there are at least 168 unit operating hours or, for a common stack or bypass stack, a calendar quarter in which there are at least 168 stack operating hours.

***surrogate. EPA should retain the quarterly stack testing and LEE options for filterable particulate and individual or total non-Hg metal HAPs.***

While under-stating the cost to conduct PM CEMS correlation testing, EPA over-estimates the cost to conduct quarterly filterable PM testing. Specifically, EPA estimates $85,127 to conduct quarterly Method 5 testing consisting of $82,000 for testing and $3,127 for site technical support. This equates to a testing cost of $20,500 per quarterly test. Stack testing vendors estimate the cost to conduct a quarterly Method 5 test consisting of 3 test runs at a volume of 4 dscm per run at $13,000. The annualized cost for stack testing is further reduced since the majority (65% based on EPA's 2019 analysis[28]) of units currently qualify as LEE units which – if the LEE option for filterable PM is preserved - would reduce the annual costs by a factor of three. In addition, based on Appendix B of EPAs technology review[29], 61% of EGUs baseline values are less than 50% of the proposed filterable PM emission limit. Stack testing and oversight quotes for quarterly filterable particulate matter stack testing and LEE particulate matter stack testing are presented in Table 7 at the sampling volume/duration of the current rule and proposed rule.

Finally, in its stack testing costs, EPA ignores the fact that a large number of sources will still have to conduct quarterly or triennial testing to demonstrate compliance with the hydrogen chloride (HCl) emission limitation. Based on records submitted in the ECMPS monitoring plans for the 4th quarter 2022, 166 stack IDs are relying on quarterly or triennial testing to demonstrate compliance with the HCl emission limitation of the MATS rule. These sources will be required to continue conducting quarterly or triennial testing for HCl even if such testing is no longer required for fPM. The incremental cost when adding a filterable PM test during the same mobilization as HCl testing is minimal as shown in Table 8.

***Table 7 –*** Cost of Quarterly fPM testing and LEE fPM testing at currently required and proposed sample volumes

| Test Type | Test Run Volume (dscm/run) | Cost/ Test, $ | Site Technical Support | Tests/ Year | Annual Testing Cost $ |
|---|---|---|---|---|---|
| EPA Preamble[30] | 4 | $ 20,500 | $ 782 | 4 | $ 85,127 |
| Quarterly fPM | 1 | $ 8,500 | $ 1,040 | 4 | $ 38,160 |
| | 4 | $ 13,000 | $ 1,560 | 4 | $ 58,240 |
| LEE fPM | 2 | $ 9,500 | $ 1,300 | 1/3 | $ 3,600 |
| | 4 | $ 12,000 | $ 1,560 | 1/3 | $ 4,520 |

[28] EPA-HQ-OAR-2018-0794-5561
[29] EPA-HQ-OAR-2018-0794

***Table 8 –*** Cost and Incremental[31] Cost of Quarterly fPM testing and LEE fPM testing at currently required and proposed sample volumes in conjunction with HCl testing

| Test Type | Test Run Volume (dscm/run) | Cost/ 3-run Test, $ | Site Technical Support | Tests/ Year | Annual Testing Cost $ |
|---|---|---|---|---|---|
| EPA Preamble[32] | 4 | $ 20,500 | $ 782 | 4 | $ 85,127 |
| Quarterly fPM incremental cost | 1 | $ 4,000 | $ 1,040 | 4 | $ 20,160 |
| | 4 | $ 8,000 | $ 1,560 | 4 | $ 38,240 |
| LEE fPM incremental cost | 2 | $ 4,500 | $ 1,300 | 1/3 | $ 1,933 |
| | 4 | $ 7,000 | $ 1,560 | 1/3 | $ 2,853 |

**5. Removing Use of PM CPMS for Compliance Determinations**

***EPA proposes to remove compliance options available under the existing rule based on limited use, not technical justification. EPA should retain the compliance options including the use of PM CPMS. CPMS have the added benefit of not requiring the varying of PM concentration for correlation testing or RCAs. Varying of PM concentration is costly, not consistently representative of true upset conditions, and has negative implications on operating equipment and the environment.***

The preamble states that PM CPMS are used for compliance at four EGUs at one site in South Carolina. EPAs database[33] identifies 10 units in 2017 and 8 units in 2019, representing 1.5% of EGUs in operation relying on "PM CPMS - 30-day rolling average". As summarized in Table 2 and Figure 7, 63% of sources that are anticipated to be in operation in 2027[34] are currently relying on quarterly stack testing or LEE testing as their selected compliance demonstrated methodology under the more robust options of the current MATS Rule. If, as proposed, EPA removes the ability to comply with MATS emission limitations by stack testing, owners and operators may consider increased use of PM CPMS for the reasons detailed in this section. The fact that CPMS was not a selected compliance option previously does not negate its value in offering compliance flexibility.

[31] Incremental cost is the additional cost to perform fPM testing in conjunction with HCl testing mobilization.
[32] 88 FR 24873 (Apr. 24, 2023).
[33] EPA-HQ-OAR-2018-0794-5561
[34] RTP adjusted EPAs 2019 database for known retirements to occur before 2027, fuel conversions, and excluding records not found in Webfire.

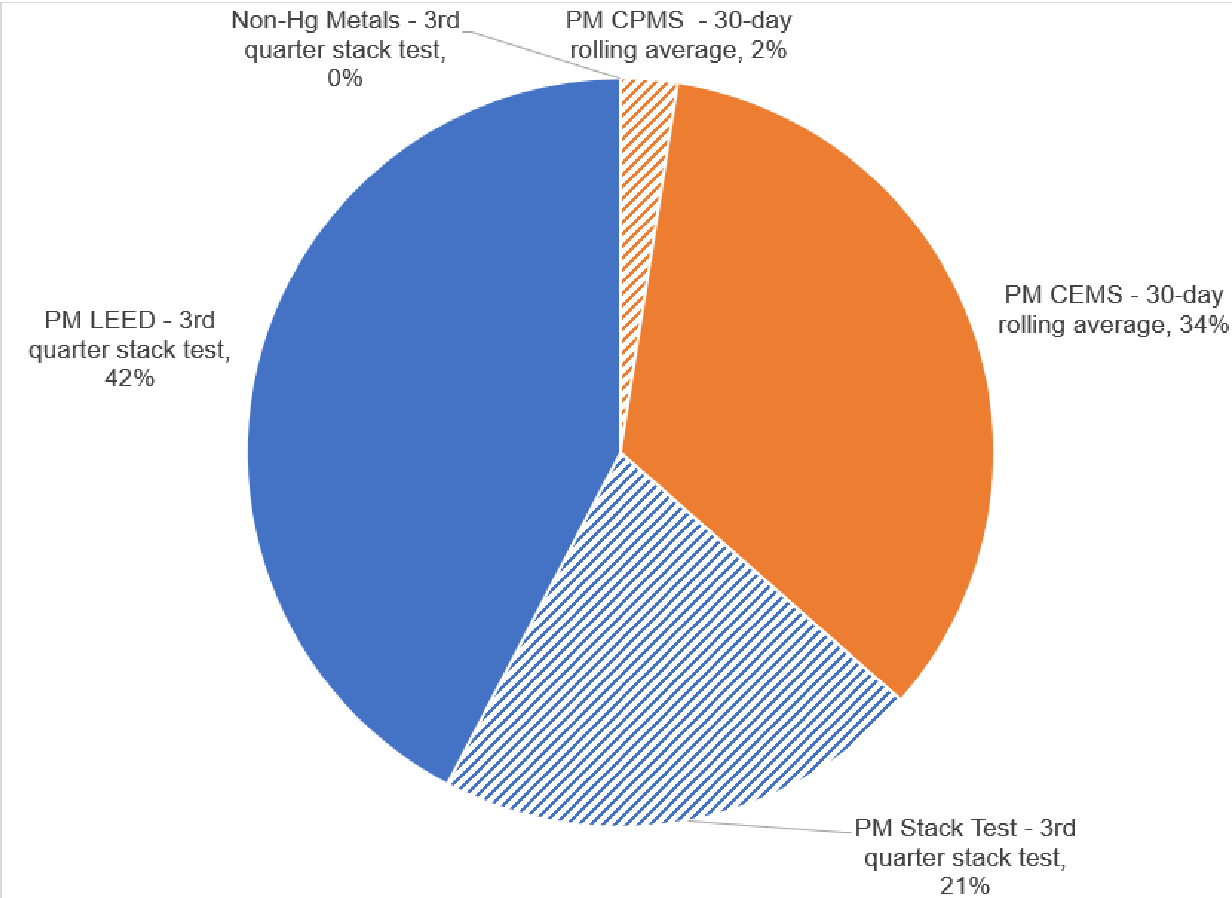


***Figure 7 –*** Selected fPM Compliance Methodology

Section 63.10023 of the current MATS Rule details the procedures for establishing PM CPMS operating limits. A linear relationship is established between the PM CPMS output signal to zero-point data and the PM concentration determined during Method 5 compliance test stack testing. If emissions during the compliance test are less than or equal to 75% of the emission limit, the operating limit is established at a value equivalent to 75% of the emission limit based on the linear relationship established. If emissions during the compliance test exceed 75% of the emission limit, the operating limit is established at a value equivalent to the average PM CPMS output recorded during the PM compliance test. The performance test is repeated annually to reassess the operating limit.

If the 30-boiler operating day average PM CPMS output exceeds the operating limit, the owner or operator must visually inspect the pollution control equipment within 48 hours and take corrective action as necessary and must conduct an additional emission compliance test within 45 days of the exceedance or at the time of the annual compliance test. The additional emission compliance test is used to verify or re-establish the CPMS operating limit. PM CPMS exceedances of the operating limit leading to more than four required performance tests in a 12-month period (rolling monthly) constitute separate violations.

By establishing operating limits, verifying operating limits on an annual basis, and establishing corrective actions if operating limits are exceeded, the MATS Rule CPMS provisions provide the benefit of quick identification and correction of control device malfunctions. A primary benefit of PM CPMS is that the need to vary PM concentration is not necessary, to establish or reassess the operating limit. As discussed in Section 3 of this document, the correlating of PM CEMS and varying PM concentrations is a significant cost both operationally and environmentally. Intentionally increasing emissions for the sole purpose of calibrating or correlating instrumentation does not make sense operationally or environmentally and should be minimized wherever possible.

EPA should maintain the option to rely on CPMS operating limits to comply with the MATS Rule. In cases where CPMS use the same measurement principle as PM CEMS, EPA should modify the CPMS operating limit to be consistent with that of PM CEMS[35]. Specifically, a source should not be limited to 75% of the emission limitation or the highest PM CPMS output during the performance test[36]. The source should be limited to the PM CPMS output that corresponds to the emission limit based on the annual compliance test. Additional testing to verify or reassess the operating limit should be conducted only if the 30-day average PM CPMS output is in excess of the operating level that is equivalent to the emission limit.

## 6. Removing Non-Hg Metals Limitations

***EPA removed compliance options available under the existing rule with no technical justification. EPA should retain existing emission limits and compliance options for Non-Hg Metals. Compliance with individual or total non-Hg metals limitations involves measuring the actual HAP, not a surrogate.***

The preamble states that the individual and total non-Hg metal emission limits are used by only one EGU[37]. If, as proposed, EPA removes the ability to comply with MATS emission limitations by stack testing for fPM it would be reasonable that sources would consider individual or total non-Hg metals stack testing. The use of individual or total non-Hg metals emission testing has the added benefit of providing a compliance determination based on the actual HAP of concern, not the surrogate (fPM).

[35] This will allow a source to use the same measurement principle as PM CEMS without intentionally creating emissions for the sole purpose of correlation as required by PS-11.
[36] The additional compliance margin (-25% of the emission limit) is not consistent with the variability allowed for PM CEMS (± 25% of the emission limit) and is likely a deterrent to the selection of this compliance option.
[37] 88 FR 24886 (April 24, 2023).

Specifically, concerns about low-level PM CEMS accuracy (See Section 2) and the increasing PM CEMS annual costs (See Section 3) will likely encourage EGU owners to re-evaluate their current MATS compliance strategy. The preamble states that if EPA were to decide to retain the non-Hg emission limits, a revised limit would be established by multiplying the revised fPM emission limit by each individual (or total) non-Hg PM ratio identified in the document entitled *Emission Factor Development for RTR Risk Modeling Dataset for Coal-and Oil-fired EGUs* memorandum[38]. RTP notes that the memorandum highlights a different non-Hg PM ratio for different control device configurations. It is unclear if EPA intends to issue a single ratio for use by all sources or if ratios would vary based on control device configuration but look forward to the opportunity to review and comment on the proposed ratios.

The preamble also states that if the option to comply with the individual (or total) non-Hg metals is retained, EPA would need to adjust the compliance determination method because quarterly testing would not be consistent with the proposed use of PM CEMS. EPA suggests that very frequent emissions testing, perhaps on the order of weekly, might be able to provide more information on compliance status. EPA does not ***need*** (emphasis added) to require continuous emissions monitoring, EPA simply must show reasonable assurance of compliance with the emission standards. Quarterly stack tests are sufficient to ensure compliance[39]. The frequency of measurement (whether continuous, weekly, quarterly, annually, or triennially) does not reflect a development in practices, processes, and control technologies that have occurred since the MACT standards were promulgated.

## 7. Removing Startup Definition 2

***EPA removed compliance options available under the existing rule with no technical justification. EPA should retain Startup Definition 2. Emissions during startup operations are not properly characterized by EPAs limit-setting methodology. EPA should retain Startup Definition 2 and should consider allowing the use of diluent cap values consistent with 40 Part 75 procedures.***

The preamble states that the alternative work practice for startup periods ("Startup Definition 2") is used by only 14 EGUs, half of which have retired or will retire by 2025[40]. If, as proposed, EPA reduces the current fPM emission limitation and removes the ability to comply with MATS emission limitations by stack testing, owners and operators may require use of Startup Definition 2 for the reasons

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[38] EPA-HQ-OAR-2018-0794-0010

[39] RTP is aware of research in the use of sorbent trap sampling for individual (or total) non-Hg metals that could be available in the future to allow quicker identification and correction of non-Hg metals emissions.(https://cfpub.epa.gov/ncer_abstracts/index.cfm/fuseaction/display.abstractDetail/abstract_id/11229/report/F).

[40] 88 FR 24885 (April 24, 2023).

detailed in this section. The fact that Startup Definition 2 was not a selected compliance option previously does not negate its value in offering compliance flexibility as incorporated in the original MATS Rule.

The bulk (approximately 2/3 - refer to Table 2 of this document) of EPAs database used to establish the proposed fPM emission limitation relies on quarterly or triennial stack testing which is conducted at normal maximum operating conditions. Emissions during startup and shutdown periods are not properly characterized in EPAs analysis since they are not captured at all for approximately 2/3 of the EGUs included in the analysis. Where PM CEMS data is used in EPAs analysis, the use of 30-boiler operating day averages smooths out variation in numeric emission values that occur.

The variations due to startup and shutdown are more pronounced due to the MATS Rules limited use of “diluent cap” values[41]. Although many existing sources using PM CEMS have been able to comply with the current numeric emission limitation (0.030 lb/mmBtu) without requiring the use of startup definition 2, that does not mean that that the emission levels immediately following generation of electricity or thermal energy for use do not impact the ability comply with a lower emission limitation. Some of those same sources may not be able to comply with the proposed numeric emission limitation while including all periods of operation based on future dispatch. If EPA wants to support the use of renewable energy sources, the proposed rule must include the operational flexibility required to incorporate more frequent cycling of coal-fired EGUS.

[41] The MATS Rule §63.10007(f)(1) allows the use of diluent cap values only during startup or shutdown hours as defined in §63.10042. Other regulatory programs relying on lb/mmBtu emission rate calculations using Method 19 F-factor methodology allow the use of diluent cap values anytime the $CO_2$ concentration is less than 5.0% (Refer to 40 CFR Part 75, Appendix F §3.3.4.2).