PGEN COMMENTS ON EPA'S PROPOSED RULE: NESHAP COAL- AND OIL- FIRED ELECTRIC UTILITY STEAM GENERATING UNITS REVIEW OF THE RESIDUAL RISK AND TECHNOLOGY REVIEW

Docket ID No. EPA-HQ-OAR-2018-0794

The Power Generators Air Coalition ("PGen") appreciates the opportunity to submit these comments on the U.S. Environmental Protection Agency's ("EPA" or the "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" ("Proposed Rule" or "Proposal").[1] The Proposed Rule proposes to amend the Mercury and Air Toxics Standards ("MATS") regulations.[2] Particularly, EPA proposes to amend the surrogate standard for non-mercury metal HAP—i.e., for filterable particulate matter (fPM)—for existing coal-fired EGUs; eliminate the individual non-Hg metal HAP standards; require the use of a Particulate Matter Continuous Emissions Monitoring System ("PM CEMS") for compliance for all units, thus eliminating the stack testing option; amend the mercury ("Hg") standard for lignite-fired EGUs; and eliminate one of two definitions of startup currently in the regulations. EPA proposes to keep the remaining standards unchanged.

PGen is an incorporated nonprofit 501(c)(6) organization whose members are diverse electric generating companies—public power, rural electric cooperatives, and investor-owned utilities—with a mix of solar, wind, hydroelectric, nuclear, and fossil generation. PGen is a collaborative effort of electric generators to share information and expertise in the interest of constructively evaluating and effectively managing air emissions to meet and exceed environmental laws and regulations and in the interest of informing sound regulation and public policy.[3] Our members include leaders in the ongoing transition to cleaner energy in the United States. PGen and its members work to ensure that environmental regulations support a clean, safe, reliable, and affordable electric system for the nation.

PGen members own and operate EGUs that are regulated under the MATS rule. Indeed, PGen members have committed substantial resources to meet and maintain compliance with MATS. Accordingly, PGen has a substantial interest in the Proposed Rule.

SUMMARY OF COMMENTS

Section I – The MATS Rule Significantly Reduced HAPs and Require No Further Revision.

- MATS has resulted in substantial decreases in HAP emissions from affected EGUs. These emissions are continuing their rapid and steady decline because of regulatory and economic pressure that are inexorably leading to additional shutdowns of coal-fired

[1] National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 88 Fed. Reg. 24,854 (proposed Apr. 24, 2023) (to be codified at 40 C.F.R. pr. 63).

[2] 40 C.F.R. Part 63, Subpart UUUUU.

[3] Additional information on PGen and its members can be found at PGen.org.

EGUs. Given this reality, (and in addition to the substantive reasons discussed in the remainder of these comments) the proposed revisions of the MATS standards are unnecessary. The proposed standards are onerous on existing coal-fired EGUs and would accelerate their retirement even further, creating increasing reliability concerns. EPA must keep reliability concerns at the forefront and ensure a smooth energy transition that will not result in electricity shortages.

Section II – Review of the Residual Risk and Technology Developments do not Justify Revising the MATS Standards.

- The risks from EGU HAP emissions are very small – for the vast majority of coal-fired EGUs, they are well below the lowest thresholds that the statute and EPA consider negligible – and becoming smaller. EPA correctly determined that no revisions to the standards were required under the residual risk prong of this review.

- That the residual risk from coal-fired EGUs is negligible also means that reducing the standards for any reason, including under the technology review prong of this review, at very high cost runs afoul of *Michigan v. EPA*.

- EPA should not revise the standards under technology review also because the Agency concedes there are no new developments in practices, processes, and control technology. This is especially appropriate here, where HAP emissions from affected facilities are decreasing on their own, as a result of the continued energy transition.

Section III – EPA's Analysis of Non-Hg Metal HAP Surrogate, fPM, Emissions Data Is Deeply Flawed and Does Not Support a Revised fPM Standard of 0.010 lb/MMBtu, Much Less a Standard as Low as 0.006 lb/MMBtu.

- EPA's proposal to revise the fPM standard for coal-fired EGUs to 0.010 lb/MMBtu is based on an "analysis" that is so deeply flawed that finalizing it would be plainly arbitrary and capricious. EPA relied on a very small set of quarterly data (either CEMS or quarterly stack tests) to characterize the "baseline fPM rates" that EPA assumes EGUs can meet readily and consistently, even though EPA has in its possession data for all EGUs subject to MATS for every quarter since at least the start of 2017. The selection criteria for the very few quarters EPA chose to consider are unexplained and arbitrary. EPA's "explanation" for its selection of the lowest of these two quarters is supported by no evidence and is contradicted by real-world data. In identifying EGUs that would have to upgrade their controls to meet the proposed revised rate of 0.010 lb/MMBtu, EPA completely ignored the need for a compliance margin.

- EPA underestimates the cost of the main type of control equipment upgrades that EPA predicts would be required to meet the proposed fPM standard of 0.010 lb/MMBtu. As a result, the proposed revision of the fPM standard is even less cost-effective than EPA says. In any event, EPA's own estimated $/ton of non-Hg metal HAP and fPM removed for the proposed fPM standard of 0.010 lb/MMBtu are about the same and, in the majority of cases, vastly exceed previous $/ton amounts that EPA had found to be *not* cost-effective. Similarly, EPA's 0.006 lb/MMBtu cost-effectiveness estimates far exceed past analogous $/ton estimates EPA found to be not cost-effective.

- Control upgrade capital costs EPA assumes would be required to meet the 0.010 lb/MMBtu standard (at units EPA's analysis determined would require such upgrades) range, based on EPA's own $100/kW cost for ESP rebuilds, from $52 million to $148 million *per unit*. Such high costs, in the current highly uncertain regulatory and economic climate for coal-fired EGUs, would almost certainly cause the owners of these units to shutdown prematurely (i.e., by the effective date of the proposed rule – likely mid-2027, if EPA adopts a three years compliance deadline). This would raise the Proposed Rule's cost even more and would make it substantially less cost-effective.

Section IV – EPA Should Retain the Individual and/or Total Non-Hg Metal HAP Standards.

- EPA offers no substantive reasons to remove the individual and total non-Hg metal HAP standards. No matter how justified a surrogate is, there will be situations in which the underlying HAP – the pollutant of real interest – may not follow the generally applicable correlation between the HAP and the surrogate that the fPM standard is based upon. For that reason, EPA should retain the flexibility for EGUs to meet either the fPM or individual/total non-Hg metal HAP standards.

- Removing the non-Hg metal HAP emission standards untethers the reduction of non-Hg metal HAP from the fPM emission limits, and runs counter to the purpose of this Proposed Rule—to regulate HAP emissions. Here, removing the individual and total non-Hg metal standards appears to confirm that the purpose of *this* Proposed Rule under Section 112(d)(6) is actually to reduce fPM emissions, regardless of any reductions in the pollutants of interest – the HAPs.

Section V – EPA's Proposal to Eliminate Quarterly Stack Testing as the Compliance Method for the fPM Surrogate Standard Is Problematic, Especially if the fPM Standard Is Reduced by Two-Thirds.

- EPA's proposal to require the use of PM CEMS for all coal-fired EGUs to demonstrate compliance with the proposed fPM surrogate standard of 0.010 lb/MMBtu glosses over significant technical challenges. This very low fPM standard would require correlation over such a limited data range that it would be "virtually impossible" to establish a valid correlation of the PM CEMS. That conclusion is supported by EPA's own actions eliminating the use of PM CEMS for compliance with the fPM standard for Portland Cement facilities. In addition, EPA is mistaken that PM CEMS are less costly than quarterly stack tests. If this were true, the majority of EGU owners would not have opted for the more expensive option. In any event, if it is now true that PM CEMS use is less costly than quarterly stack tests, no rule change would be needed: rational economic actors would choose PM CEMS anyway (assuming they are feasible, which would not be the case if EPA lowers the standard as proposed).

- Should EPA insist on requiring PM CEMS to demonstrate compliance, EPA should exclude from PM CEMS requirements EGUs that will retire consistent with the December 31, 2028 option in the 2020 Effluent Limitation Guidelines ("ELG") rule.

Section VI – Hg Standard for Non-Lignite-Fired EGUs Should not be Revised.

- PGen agrees with EPA's proposed decision to retain the Hg emission standard of 1.2 lb/TBtu for non-lignite fired EGUs. Analysis of available Hg emissions demonstrates that annual average rates added together with the standard deviation, which accounts for the range of variability in the data, approach the current 1.2 lb/TBtu standard.

- In addition, the variability in myriad factors that affect Hg emission removal rates, such as Hg content, sorbent composition, sorbent injection rates, co-benefits, Hg re-emission, and electricity load variability, supports retaining the current Hg standard for non-lignite EGUs.

Section VII – Acid Gas and Organic HAP Standards Should not be Revised.

- PGen agrees with EPA that no revisions to the Acid Gas and Organic HAP standards are necessary. PGen agrees with EPA that there are no new developments in practices, processes, and control technology that would result in cost-effective emission reductions.

Section VIII – EPA's Rationale for Revising the Hg Standard for Lignite EGUs Is Flawed.

- The fundamental premise of EPA's proposed revisions to the Hg standard for lignite-fired EGUs is that lignite coal and sub-bituminous PRB coal have similar Hg content, halogen content, and alkalinity, and that therefore "it is difficult to justify why those units should not meet a similar level of Hg control." This statement and conclusion are wrong, because despite some similarities, the *differences* between lignite and sub-bituminous PRB coal result in very different Hg removal performance for the main Hg control technology available for lignite-fired EGUs – halogenated activated carbon sorbent injection.

- The most influential differences in limiting the Hg removal effectiveness of sorbent injection in lignite coal as compared to PRB coal are Hg content and sulfur trioxide (SO_3) in the flue gas. EPA ignores data about the larger variability in and higher Hg content of lignite, which would necessitate unrealistic and unachievable removal efficiencies of up to 97 percent to meet a standard of 1.2 lb/TBtu. EPA also ignores the well-documented impact of flue gas SO_3 on Hg removal efficiency of sorbent injection. Lignite has higher sulfur content than PRB coal, which, combined with equal or lower total alkali relative to sulfur, allows much higher levels of SO_3 in lignite-generated flue gas. This imposes very significant limitations on the effectiveness of sorbent injection to control Hg emissions.

Section IX – EPA Should Adopt a Compliance Date for any Revised Standard of Three Years After the Effective Date of the Final Rule and Provide Additional Flexibility.

- PGen requests that EPA provide a compliance date of three years after the effective date of the final rule. This timeline is necessary to evaluate whether additional controls are needed, determine which controls are needed, and conduct an analysis whether affected EGUs can meet the revised controls and remain viable. More importantly, affected EGUs that must upgrade or construct controls will need the remaining time to finance, design, procure, build/modify, and effectively operate the emission control and monitoring equipment to comply with the revised standard.

- EPA should anticipate that some affected EGUs may need more time to come to compliance with the revised standard and provide guidance in the final rule regarding one-year extensions under CAA section 112(i)(3), as it did in the original MATS rulemaking.

- If EPA decides to proceed with revised standards in this rulemaking, it should create a subcategory for coal-fired EGUs that elect by the compliance date for the revised standards (i.e., mid-2027) to retire by January 1, 2032. EPA should not revise any standards for this subcategory, consistent with its actions under recent rulemakings.

Section X – EPA Should Correct Errors in its IPM Model and Evaluate the Impact of its Proposed Rules on the Reliability of the U.S. Electric Power Grid.

- EPA should correct the multiple errors in the IPM modeling in this rulemaking (and other recent rulemakings). These errors propagate through the analysis of the costs of the Proposed Rule and skew the amount of generation that likely would have to shut down prematurely as a result of the rule if finalized as proposed.

- EPA should also carefully and seriously evaluate this Proposed Rule, *as well as* the several rules affecting the same EGUs that EPA has recently either finalized or proposed on the reliability of the Nation's electric power grid. The multitude of recently finalized and proposed regulations that seek to impose substantial costs on fossil-fired generation will inevitably lead to premature retirements, putting the reliability of the power grid at risk. The impact of these rules, including this Proposed Rule, on reliability is an important aspect of the problem. EPA should give it the consideration it deserves.

I. MATS HAS LED TO SIGNIFICANT REDUCTIONS IN HAP EMISSIONS FROM AFFECTED FACILITIES.

The preamble to the Proposed Rule discusses the success of the MATS rule, which was promulgated in 2012.[4] As EPA notes, 2019 data show that affected EGUs have reduced their mercury emissions by 86 percent, acid gas HAP emissions by 96 percent, and non-mercury metal

[4] 88 Fed. Reg. at 24,857.

HAP emissions by 81 percent compared to pre-MATS levels.[5] In EPA's 2020 National Emission Inventory ("NEI") data, coal- and oil- fired EGUs contribute significantly less mercury emissions and make up only 11.6 percent of all mercury emissions from all reporting sources.[6] Similarly, coal- and oil-fired EGU non-mercury metal HAP emissions account for 11.5 percent of total non-mercury metal HAPs[7] from all reporting sources.[8]

More recent data show greater HAP reductions from EGUs. EPA's Emission Reduction Progress Report shows that coal- and oil-fired EGU sources regulated under MATS emitted a combined 3 tons per year ("tpy") of mercury in 2021, a 90 percent decrease of mercury from 29 tpy pre-MATS in 2010.[9] Non-mercury metal HAPs from coal- and oil-fired EGU sources emitted 246 tpy in 2020, which is a 70 percent decrease from 854 tpy in 2011.[10]

While the most drastic reductions in mercury and non-mercury metal HAP occurred around the compliance deadline for MATS, mostly due to substantial investments by PGen members and other EGU owners to meet the MATS standards, EGU HAP emissions continue to decline further, absent any revisions to the MATS standards, due in large part to regulatory pressure (i.e., other EGU regulations EPA has and is promulgating) as well as economic pressures that are leading inexorably to increasing shutdowns of coal-fired EGUs. In 2011, before MATS was promulgated, electric utilities owned 332 coal-fired EGUs in the U.S.[11] In 2021, there are now 169 coal-fired EGUs in the U.S., a reduction of over 50 percent.[12] According to EPA, based only on current public announcements of EGU shutdowns, there will be accelerated retirements of over 50 percent of the remaining coal-fired EGUs in the U.S. by 2040.[13] In truth, many more coal-fired EGUs are likely to retire well before 2040, even if public announcements to that effect have not been made. For these reasons, EPA should not seek to revise the MATS standard as it proposes in the Proposed Rule. Not only are EGU HAPs continuing their steady and substantial

[5] *Id.*

[6] EPA, 2020 NEI Supporting Data and Summaries, https://www.epa.gov/air-emissions-inventories/2020-nei-supporting-data-and-summaries (last visited on May 27, 2023).

[7] Non-Mercury metal HAPs concerning coal- and oil-fired EGUs include Antimony, Arsenic, Beryllium, Cadmium, Chromium, Cobalt, Lead, Manganese, Nickel, and Selenium. *See* 88 Fed. Reg. at 24,861 (Table 1-Emission Limits for Existing Affected EGUs).

[8] EPA, 2020 NEI Supporting Data and Summaries, https://www.epa.gov/air-emissions-inventories/2020-nei-supporting-data-and-summaries (last visited on May 27, 2023).

[9] EPA, Emissions Reductions Progress Reports, https://www3.epa.gov/airmarkets/progress/reports/emissions_reductions_mats.html#figure1 (last visited on May 27, 2023).

[10] EPA, 2020 NEI Supporting Data and Summaries, https://www.epa.gov/air-emissions-inventories/2020-nei-supporting-data-and-summaries (last visited on May 27, 2023).

[11] U.S. EIA, ELECTRIC POWER ANNUAL 2021 REPORT, https://www.eia.gov/electricity/annual/ (last visited on May 27, 2023).

[12] *Id*.

[13] EPA, POWER SECTOR TRENDS TECHNICAL SUPPORT DOCUMENT, at 9 (Apr. 2023) ("Between 2021 and 2040, utilities have already announced publicly plans to retire a total of 118 GW of coal-fired EGUs, over half of the remaining coal fleet [in the U.S.]").

decline regardless of whether the Proposed Rule is finalized as proposed; as discussed below, the risk that EGU HAP emissions pose is minute, and the Proposed Rule itself–if finalized–would result in substantial additional near term-shutdowns of coal-fired EGUs. This would further exacerbate the reliability concerns that power generators and regional transmission operators ("RTOs") have been grappling with and warning about.[14]

II. NEITHER RESIDUAL RISK NOR TECHNOLOGY DEVELOPMENTS JUSTIFY REVISING THE MATS STANDARDS.

This rulemaking is a risk and technology review ("RTR") of HAP standards for the coal- and oil-fired EGU source category–more precisely, a reconsideration of the RTR rule promulgated by the Agency in 2020.[15] In the 2020 RTR, EPA conducted a thorough residual risk analysis and concluded that post-MATS HAP emissions from the entire category–both coal- and oil-fired EGUs–pose such small risks that they provide an "ample margin of safety to protect public health."[16] EPA also conducted a thorough review of control technology in this mature industry and concluded that there were no new developments in practices, processes, and control technologies that would warrant consideration of whether the standards should be revised under section 112(d)(6) of the CAA.[17]

A. The Risks from EGU HAP Emissions Are Very Small And Becoming Smaller.

In this rulemaking, EPA reaffirms the conclusions the agency made in the 2020 residual risk assessment and explains it is not "reopening" its 2020 determination because "the risk analysis was a rigorous and robust analytical review using approaches and methodologies that are consistent with [other] risk analyses."[18] PGen agrees with and supports EPA's conclusion.

EPA's risk assessment found that maximum chronic cancer inhalation risk–i.e., the cancer risk from emission potentially inhaled by sensitive individual–from any EGU facility was 9-in-1 million, with the major contributor being nickel emissions from *oil*-fired EGUs.[19] Indeed, the maximum chronic inhalation risk from coal-fired EGUs was 0.3-in-1 million.[20] This level of risk is an order of magnitude lower than the threshold the statute considers so negligible as to require

[14] *See, e.g.*, NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION, 2022 SUMMER RELIABILITY ASSESSMENT, at 4 (2022); PJM, ENERGY TRANSITION IN PJM: RESOURCE RETIREMENTS, REPLACEMENTS & RISKS, at 1 (2023).

[15] *See* 88 Fed. Reg. at 24,854 ("These proposed amendments are the result of the EPA's review of the May 22, 2020 residual risk and technology review.").

[16] 42 U.S.C. 7412(f)(2)(A).

[17] 88 Fed. Reg. at 24,865 (evaluation technology developments under 42 U.S.C. 7412(d)(6)).

[18] *Id.* at 24,866.

[19] *Id.* at 24,863.

[20] EPA, RESIDUAL RISK ASSESSMENT FOR THE COAL- AND OIL-FIRED EGU SOURCE CATEGORY IN SUPPORT OF THE 2020 RISK AND TECHNOLOGY REVIEW FINAL RULE, at Table 2a (Sept. 2019) (Docket ID No. EPA-HQ-OAR-2018-0794-5786).

no further regulation.[21] The maximum chronic non-cancer target organ-specific hazard index was 0.2, again driven by cobalt and nickel emissions from oil-fired EGUs, and that is in any event well below EPA's Target Organ-Specific Hazard Index ("TOSHI") threshold of 1.[22] EPA made similar determinations for inhalation risks from "allowable" and facility-wide emissions. The worst-case hazard quotient ("HQ") from acute emissions was 0.09, driven by arsenic emissions, well below (by one order of magnitude less than) EPA's threshold of 1.[23]

In EPA's multipathway risk screening and site-specific refinements, EPA found that the highest cancer risk any EGU presented in a Tier 3 screening was 50-in-1 million.[24] EPA did not further refine the risk level because EPA's finding was significantly below the Agency's "acceptable risk" threshold of 100-in-1 million, and EPA "expected the actual risk from a site-specific assessment to further lower the Tier 2 screening value by a factor of 50."[25] Further refined non-cancer risk assessment of the MATS existing standards showed a maximum hazard quotient ("HQ") for mercury from EGUs – through fish consumption – of 0.06, which again is more than a magnitude below EPA's threshold of 1.[26]

Finally, the Agency conducted an environmental risk screening, which showed no adverse environmental effect as a result of HAP emissions from the coal- and oil-fired EGU source category.[27]

Given the extremely small risk attributable to EGU HAP emissions after the implementation of MATS, EPA unsurprisingly concluded that the MATS standards provided an "ample margin of safety to protect public health" and that no further revisions of these standards were warranted.

Nonetheless, EPA proposes to reverse course and to reduce standards for *coal-fired* EGUs under technology review despite that EPA found the risks to be minimal and primarily driven by nickel emissions from *oil-fired* EGUs, and that EPA concedes there have been no new developments in practices, processes, and control technologies.

PGen recognizes that the technology review prong is separate from the residual risk review. But in this case, the extremely low residual risk remaining after MATS is at least relevant to an essential aspect of the technology review for coal-fired EGUs: cost and cost-benefit. And the cost is very high–more than $900 million in upfront capital cost and nearly $100 million

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[21] Section 112(f) establishes 1-in-a-million as the level of residual risk below which no further revision of the standard on the basis of risk is needed. Indeed, Congress provided that the Agency may delist a source category under and cease to regulate it under Section 112 if no source in that category emits HAP with a risk of 1-in-a-million. CAA § 109(c), 42 U.S.C. § 7412(c)(9).

[22] *See* 88 Fed. Reg. at 24,863, 24,865 (providing that a non-cancer hazard index of 1 is conceptually similar to a cancer risk of 1-in-1-million, which is the level the statute suggest is extremely small.).

[23] 88 Fed. Reg. at 24,863.

[24] *Id*. at 24,864.

[25] *Id*.

[26] *Id*.

[27] *Id*. at 24,864-65.

annually, based on EPA's own underestimated cost for major ESP rebuilds and the number of units that would have to construct such upgrades.[28] Yet, nowhere in the record does EPA quantify *any* benefit from reducing HAPs from coal-fired EGUs beyond those achieved by the existing MATS regulations. That is not surprising. If the residual risk from coal-fired EGUs HAP emissions is extremely small, there is hardly any benefit from reducing HAPs further from these units. EPA all but concedes those facts by claiming in its Regulatory Impact Assessment only "co-benefits" derived from reductions in non-HAPs that are not the target of Section 112 of the CAA or this rulemaking.

As a matter of common sense, EPA should not seek to impose almost $2 billion of cost on any source category when there is no benefit associated with reducing the same pollutants the statute targets. EPA certainly should not do so for an industry that is reducing its emissions at a high pace because it is on the way to retiring most, if not all, units in the source category in little over a decade. But more importantly, as the Supreme Court admonished in *Michigan v. EPA*, the "[c]onsideration of cost reflects the understanding that reasonable regulation ordinarily requires paying attention to the advantages *and* disadvantages of agency decisions."[29] The Court faulted EPA's refusal to "consider whether the costs of its decision outweighed the benefits"[30] in that rulemaking, explaining "[o]ne would not say that it is even rational … to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits."[31]

Here, it is well-established that cost *is* a major consideration in technology review rulemaking.[32] Under *Michigan*, therefore, EPA must consider the costs of *this* regulation under Section 112 of the Act in relation to benefits intended by the statutory requirement mandating *this* regulation– HAP reductions.[33] Moreover, this is not any source category; it is the source category that was the subject of *Michigan*, and that may be regulated under Section 112 only upon a determination that it is "appropriate and necessary" to do so.[34] Since *Michigan* held that cost and benefits must be considered in determining whether it is "appropriate" to regulate EGUs under Section 112 in the first place, it necessarily follows that the same appropriate and necessary threshold must also apply to this RTR rulemaking, which is merely a follow-on to the initial MACT rulemaking.

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[28] *See* Cichanowicz, et al., "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," App. A, Fig. A-1 (June 19, 2023) (hereinafter "Industry Study") (Attachment A to these comments). As shown in Figure A-1 of the Industry Report, the sum of the capital costs for controls required to meet the proposed fPM standard, based on EPA's own underestimated $100/kW for major ESP upgrades and the units identified by EPA for upgrades, are about $900 million. A more realistic accounting of the units that would require upgrades controls, simply providing for a modest 20% compliance margin, *see* Industry Report, App. A. Table A-1, results in upfront capital costs of more than $1.8 billion.

[29] 576 U.S. 743, 753 (2015) (emphasis in original).

[30] *Id.* at 750.

[31] *Id.* at 752.

[32] *See Ass'n of Battery Recyclers, Inc v. EPA*, 716 F.3d 667, 673 (D.C. Cir. 2013).

[33] *See Michigan v. EPA*, 576 U.S. 743, 751 (2015).

[34] *Id.* at 743.

B. EPA Concedes There are No New Practices, Processes, and Control Technologies.

EPA may revise the MATS standards under 112(d)(6) on the basis of new developments in practices, processes, and control technologies.[35] EPA found no new developments in practices, processes, and control technologies for this source category in its 2020 RTR.[36] EPA concedes the same finding in this Proposed Rule.[37] EPA's finding is not surprising. EGUs are a mature industry that has been subject to CAA regulation since the inception of the Act more than 40 years ago. The types of controls that were well-established in 2012, when EPA promulgated the MATS rule, remain the same in 2020. PGen members, whose business requires the installation and operation of the controls required to meet MATS, are unaware of any new or improved practices, processes, or control technologies. Because there are no new practices, processes, and control technologies, EPA should not seek – indeed it has no authority – to revise the MATS standards under Section 112(d)(6).

Notwithstanding the lack of any new or improved practices, processes, and control technologies EPA nonetheless proposes to revise some MATS standards under Section 112(d)(6) on the grounds that affected facilities are generally performing better than the standard. At bottom, EPA claims that observing emissions lower than the standard, in and of itself, is a "development" that warrants revising the standard under technology review. For this proposition, EPA cites past technology review rulemakings, the Coke Oven Batteries RTR,[38] the Ferroalloy Production RTR,[39] and the Wool Fiberglass Manufacturing RTR.[40] However, the cited actions provide no support to EPA's proposal to revise the MATS standards. In the Coke Oven Batteries RTR, EPA identified no new developments in control technology, but it revised the standard based on improved developments in practices and processes.[41] EPA's Ferroalloys Production RTR found "advancements in emission control measures" warranting lower emission standards under Section 112(d)(6).[42]

Similarly, in the Wool Fiberglass Manufacturing RTR, EPA found improvements in control technology, the use of electrostatic precipitators, and developments in pollution prevention

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[35] 42 U.S.C. 7412(d)(6).

[36] 88 Fed. Reg. at 24,865.

[37] 88 Fed. Reg. at 24,868 (conceding "our review of fPM compliance data for coal-fired EGUs indicated no new practices, process, or control technologies for non-Hg metal HAP").

[38] National Emission Standards for Coke Oven Batteries, 69 Fed. Reg. 48,338 (proposed Aug. 9, 2004).

[39] National Emission Standards for Hazardous Air Pollutants: Ferroalloys Production, 79 Fed. Reg. 60,238 (Oct. 6, 2014).

[40] National Emission Standards for Hazardous Air Pollutants for Wool Fiberglass Manufacturing; Rotary Spin Lines Technology Review, 82 Fed. Reg. 40,970 (Aug. 29, 2017).

[41] 69 Fed. Reg. at 48,351 ("[O]ur review of emission data revealed that existing MACT track batteries can achieve a level of control for door leaks and topside leaks more stringent than that required by the 1993 national emission standards … achieved in practice on a continuing basis through diligent work practices to identify and stop leaks.").

[42] 78 Fed. Reg. at 60,258.

practices.[43] Remarkably, however, EPA did not lower the standard for formaldehyde, despite data demonstrating these developments would result in lower actual emissions, because EPA saw a continuing downward trend in formaldehyde emissions from that industry and concluded that revising the standard merely to accelerate that trend slightly for some sources was not necessary.[44]

In short, in each of the RTRs EPA cites, EPA in fact found developments in practices, processes, or control technologies that warranted revisions of the respective standards. Here, EPA found no new developments in practices, processes, and control technologies. EPA merely found that fPM actual emissions were generally lower than the current emission limits. Without identifying any "development" as required in section 112(d)(6), EPA is not authorized to lower the emission standard of fPM in MATS. Moreover, even if EPA has such authority, EPA should treat EGU affected facilities as it treated Wool Fiberglass Manufacturing facilities in that RTR. EPA is fully aware that other regulatory programs, legislation, and the economics of power generation are leading inexorably to substantial retirements of coal-fired EGUs in the next decade or so. The reductions in HAPS (as well as all pollutants) from these retirements will dwarf any reductions that the Proposed Rule would mandate. In these circumstances, it makes no sense for EPA to pile on yet another costly, unnecessary mandate.

III. EPA'S ANALYSIS OF NON-HG METAL HAP SURROGATE, fPM, EMISSIONS DATA IS DEEPLY FLAWED AND DOES NOT SUPPORT A REVISED fPM STANDARD OF 0.010 lb/MMBtu, MUCH LESS A STANDARD AS LOW AS 0.006 lb/MMBtu.

EPA's proposal to revise the fPM standard for coal-fired EGUs to 0.010 lb/MMBtu is based on an "analysis" that is so deeply flawed that finalizing it would be plainly arbitrary and capricious. EPA analysis suffers from the following flaws:

- EPA relied on a very small set of quarterly data (either CEMS or quarterly stack tests) to characterize the emissions rates that EGUs can meet readily, even though EPA has in its possession data for all EGUs subject to MATS for every quarter since at least the start of 2017.

- The selection criteria for the very few quarters EPA chose to consider are unexplained and arbitrary.

- EPA's extremely truncated data set is not–indeed, it cannot–be representative of the units' long-term performance, quarter after quarter. This truncated data set allowed EPA to turn a blind eye to the variability in emissions rates that EGUs experience.

- Of two out of at least 20 quarters of available data for each EGU, EPA selected the quarter exhibiting the least emission rate (arbitrarily, at least for PM CEMS units, on the last day of the quarter) as indicative of the emission rate the unit must be capable of

[43] 82 Fed. Reg. at 40,975.

[44] *Id*.

achieving consistently. EPA's "explanation" as to why it selected the lowest of these two quarters is supported by no evidence and is contradicted by real-world data.

- In identifying EGUs that would have to upgrade their controls to meet the proposed revised rate of 0.010 lb/MMBtu, EPA completely ignored the need for a compliance margin. If the standard were lowered to 0.010 lb/MMBtu, EGU owners would have to target 0.005 lb/MMBtu to, at most, 0.008 lb/MMBtu, to have an adequate compliance margin that ensures they would be able to meet the proposed standard.

- EPA underestimates the cost of the main type of control equipment upgrades that EPA predicts would be required to meet the proposed standard of 0.010 lb/MMBtu. EPA estimates an ESP rebuild would cost $75-$100/kW. The Industry Study looked at four real-world ESP rebuild projects. The costs of three out of the four projects exceed the high end of EPA's range, with two at almost twice that amount (i.e., about $200/kW). Based on the four real-world ESP rebuilds, the mean cost is $133/kW. As a result, the proposed revision of the fPM standard is even less cost-effective than EPA says.

- Control upgrade capital costs EPA assumes would be required to meet the 0.010 lb/MMBtu standard (at units EPA's analysis determined would require such upgrades) range, based on EPA's own $100/kW cost for ESP rebuilds, from $52 million to $148 million *per unit*. Such high costs, in the current highly uncertain regulatory and economic climate (no pun intended) for coal-fired EGUs, would almost certainly cause the owners of these units to shut them down prematurely (i.e., by the effective date of the proposed rule – likely mid-2027, if EPA adopts a three years compliance deadline). This would raise the Proposed Rule's cost even more and would make it substantially less cost-effective. The premature retirement of these units would also pose a significant threat to the reliability of the power grid.

- EPA's own estimated $/ton of fPM removed for the proposed fPM standard of 0.010 lb/MMBtu is about the same and, in the majority of cases, vastly exceed previous $/ton amounts that EPA had found to be *not* cost-effective. Similarly, EPA's 0.006 lb/MMBtu cost-effectiveness estimates far exceed past analogous $/ton estimates EPA found to be not cost-effective.

A. EPA's Conclusion are Based on a Truncated and Unrepresentative Set of Data, Even Though EPA has in its Possession Data for Every Quarter for Every Unit Since MATS Took Effect.

EPA's rationale for revising the MATS fPM standard hinges on an analysis replete with errors and unexplained and arbitrary selections. As an initial matter, it is a mystery why EPA excluded from its database (i.e., the inventory of EGUs it analyzed) units that "will shut or no longer burn coal/oil by December 31, 2028." Assuming EPA adopts a three-year compliance deadline for a revised standard, that deadline would likely be about mid-2027, which means units that will shut down by the end of 2028 would have to meet the revised standard for a year and half. If these units can readily meet the revised standard (and some units can), they will presumably continue to do so between mid-2027 and the end of 2028. But what are the units that currently do not meet the revised standard consistently supposed to do? (Surely, expensive control upgrades cannot be justified for a year and a half of operation – so shut down may be the only option.) And why did EPA exclude these units from its database and not account for the costs of their likely premature (by 1.5 years) shutdowns? EPA does not explain.

Additional flaws in EPA's analysis are discussed in detail in the attached technical review (the Industry Study). As this report explains, EPA's database of units/rates that would be subject to the Proposed Rule is curiously truncated. In assigning an fPM emission rate to the units in its database, EPA proceeded as follows:

> 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).[45]

There is no explanation why EPA selected certain quarters in 2017, 2019, and occasionally 2021, even though EPA has in its possession compliance data for every quarter EGUs have operated since at least 2017.[46] Indeed, EPA uses only data from two quarters (collectively, in 2017, 2019, and 2021) for the vast majority (80%) of units in its database out of at least 20 quarters available (from 2017 to 2022). Nor is there any explanation about why the quarters EPA considered in 2017 were "variable" (why not all quarters in 2017, or a specific quarter or two for all units?); about why EPA was more consistent in selecting "quarter three" in 2019, but then also "occasionally" quarter four; and about why it considered 2021 for only a subset of units, other than biasing the "baseline PM rates" downwards for units that emitted more than 0.010 lb/MMBtu during 2017 and 2019.

After comparing the quarters it chose for each unit (for most of the units, just two quarters), EPA selected the quarter with the "lowest" fPM emission rate as representative of the performance of each unit. EPA then determined the 99th percentile of the emissions measured during that quarter as indicative of the emission rate the unit can readily meet with current controls.[47] According to EPA, "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,"[48] meaning

[45] EPA, 2023 Technology Review for the Coal- and Oil-Fired EGU source Category, at 2 (2023) (Docket ID No. EPA-HQ-OAR-2018-0794-5786) [hereinafter Technology Review Memo].

[46] The MATS rule requires reporting on quarterly compliance data to EPA. EGUs have diligently complied with these requirements since MATS standards became effective (April 2015).

[47] While the 99th percentile number may be a reasonable way to account for the variability of emissions *during the selected quarter* (that does not account for variability from quarter to quarter and year to year) for units that currently demonstrate compliance using PM CEMS, it is entirely unreasonable for units that currently demonstrate compliance using quarterly stack tests – which are a majority of the units in the database. Putting aside that calculating a 95th percentile based on three data points (from three one-hour test runs) is meaningless, the results of a single stack test (consisting of three one-hour runs during one day) cannot possibly bear any resemblance to variability during the quarter, much less across quarters and years.

[48] Technology Review Memo, at 4.

that EPA's analysis assumes that because a particular unit met this emission rate in one quarter under its current configuration, it must necessarily be able to meet it in every other quarter and indefinitely into the future. That is incorrect. The "actions individual EGUs have already taken to improve and maintain PM emissions" is not the only factor affecting fPM emissions. There is short-term and long-term inherent variability in the performance (emission rate) of any unit, due to myriad factors, including fuel variations, ash content, operating conditions, ambient conditions, load, duty, and many more. The variability of emissions within a quarter cannot possibly account for this longer-term variability. And again, while this statement is certainly true for units that use PM CEMS for compliance, it is even more emphatically so for units that use stack tests for compliance. The "variability" among three (highly-correlated) hours is certainly not indicative of variability during the 2,160 hours in that quarter, and much less the thousands of hours in other quarters and years.

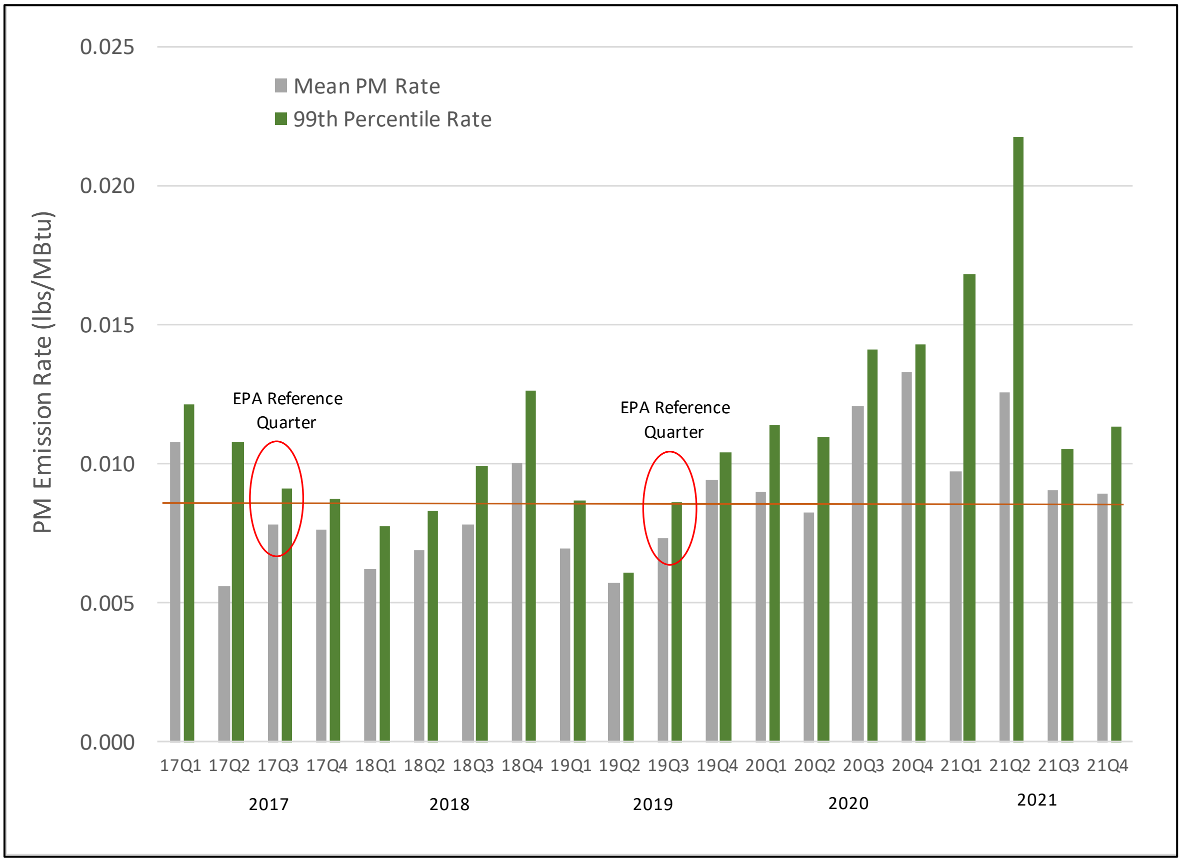
Putting aside the unexplained and arbitrary nature of which years and which quarters in those years EPA selected for its analysis, the much larger problem with EPA's failure to consider all available data for the units in its database is that it led the Agency to ignore the long-term variability in units' performance. This is illustrated well in Figure 3-3 of the Industry Study (reproduced below), which shows both the average rates and 99th percentile rates for one EGU subject to the Proposed Rule for each of the 20 available quarters from 2017 to 2021.[49] The two quarters that EPA happened to look at for this unit were Q3-2017 and Q3-2019. EPA selected the latter as defining the "baseline" rate for the unit, a 99th percentile rate of 0.0086 lb/MMBtu. The long-term variability of this unit's performance is obviously much larger than EPA acknowledges (or, apparently, is aware of). The 99th percentile rates were higher than the baseline rate selected by EPA in 16 out of the 20 quarters available. Half of the quarters have 99th percentile rates that exceed the proposed standard of 0.010 lb/MMBtu.

Moreover, as the owner of the Coronado Generating Station explains in its own comments on the Proposed Rule, Q3-2019 was unusual and not at all representative of the units' operations most of the time.[50] Indeed, the Coronado units operated at very high capacity factors during Q3-2019, likely due to very high demand for power in Arizona that Summer, and that was likely the reason of a lower fPM emission rate for these units. Indeed, the Coronado units were base loaded during that quarter, operating 99.9% of all hours in Q3-2019, thus avoiding cold starts as well as frequent load changes. EPA's facile assumption – that the units must be able to consistently emit at less than 0.0086 lb/MMBtu (99 percent of the time) because they did so in Q3-2019 – is, therefore, divorced from reality. Nor can the performance of the Coronado units during Q3-2019 be ascribed to ESP maintenance that the units underwent before that quarter. The 99th percentile rate during the immediately following quarter (Q4-2019) was more than 0.0086 lb/MMBtu; in fact, it was more than 0.010 lb/MMBtu. Such an increase, so soon after the performance observed in Q3-2019, cannot possibly be explained by ESP maintenance activity. And that is true for every quarter from Q4-2019 to the end of 2021, each of which experienced a 99th percentile rate of more than 0.010 lb/MMBtu. Surely, the units underwent ESP maintenance during that period, yet the fPM rate was never as low as Q3-2019. Indeed, the ESP maintenance activities

[49] This unit uses PM CEMS to demonstrate compliance, so the 99th percentile rate is not a meaningless number, at least not in characterizing emissions during each quarter.

[50] *See* Comments of Salt River Project on Proposed Rule.

undertaken at Coronado Units 1 and 2 in Q1-2019 and Q1-2020 are very similar.[51] Yet, these units emitted at 0.086 lb/MMBtu in Q3-2019 and at 0.0141 lb/MMBtu in Q3-2020. The variability in the fPM emission rate for the Coronado units is due to myriad factors, likely chief among them the units' duty and coal variability. That a unit happened to emit at 0.086 lb/MMBtu in Q3-2019 is no indication that such a unit would always be able to meet this rate.



Coronado Generating Station 20 Operating Quarters[52]

EPA's decision to turn a "blind eye" to this relevant information, for Coronado as well as all for other units the Agency analyzed[53] – i.e., the emission rate data for 20 quarters already in the Agency's possession, instead of two arbitrary quarters of data – and to account for the variability in units' performance is arbitrary and capricious.[54] The inherent variability of EGU emission

[51] *Compare* Salt River Project, "ESP BMP QUARTERLY REVIEW – Q1 2019" to Salt River Project, "ESP BMP QUARTERLY REVIEW – Q1 2020." Both of these reports are included in Attachment B to these comments.

[52] Industry Study at 10, Fig. 3-3.

[53] Appendix B of the Industry Study contains figures similar to Coronado's showing long-term variability in fPM emission rates for other units. Due to EPA's refusal to extend the comment period for this Proposed Rule, the Industry Study authors were unable to add additional figures, though the data surely exists in EPA's possession. Certain PGen members provided additional figures similar to those in the Industry Study. These figures are in the Appendix to these comments.

[54] *Natural Resources Def. Council v. EPA*, 808 F.3d 556, 574 (D.C. Cir. 2015).

rates is “an important aspect of the problem”; EPA’s failure to consider it is arbitrary and capricious.[55]

B. EPA’s Proposed Revision of the non-Hg Metal HAP Surrogate, fPM, Standard is Not Cost-Effective.

It is well-established that cost-effectiveness is an important consideration in technology review under Section 112(d)(6).[56] Indeed, EPA undertook cost-effectiveness analyses for three possible fPM standards: 0.015, 0.010, and 0.006 lb/MMBtu.[57] Largely based on these analyses, EPA is proposing a revised standard of 0.010 lb/MMBtu; and it rejected the lower, 0.006 lb/MMBtu standard because it is not cost-effective, although it also is soliciting comments on this more stringent standard.[58] PGen agrees with EPA that lowering the standard to 0.006 lb/MMBtu at $25.6 million per ton of total non-Hg metal HAP reduced is not cost-effective. As explained below, however, PGen believes that the proposed 0.010 lb/MMBtu standard is also not cost-effective.

For the proposed 0.010 lb/MMBtu standard, the Agency estimates that the revised standard would only impact 20 affected EGUs and bear an annual cost between $77.3 million and $93.3 million for a total fPM reduction benefit of 2,074 tpy and total non-Hg metal HAP reduction of 6.34 tpy.[59] A reduction of 6.34 tpy is equivalent to a 2.57 percent reduction of total non-Hg metal HAP emissions reported for this sector compared to 2020 emission rates.[60] Across all emission sectors the proposed reduction represents a 0.30 percent reduction of fPM emissions compared to 2020 emission rates.[61] These are small reductions, at high cost. Based on the costs and emission reductions, EPA calculated a cost-effectiveness ratio–i.e., the estimated cost to reduce one ton of total non-Hg metal HAPs–of $12,200,000 to $14,700,00.[62]

There are multiple flaws in EPA’s evaluation and its conclusions. First, EPA’s estimate that only 20 units are likely to incur any costs to meet the new standard is incorrect. There are two reasons. As an initial matter, it is fatuous, as discussed above, to conclude that a unit that happened to emit in a single quarter out of the last 20 quarters at 0.010 lb/MMBtu or less will not be required to do anything to meet the proposed revised standard. As the chart above illustrates, even a unit that EPA says has a “baseline fPM rate” of 0.086 lb/MMBtu was actually emitting more than

[55] *See Motor Vehicle Manufacturers Ass’n v. State Farm Auto Mut. Ins. Co.*, 463 U.S. 29, 43 (1983).

[56] *Ass’n of Battery Recyclers*, 716 F.3d at 673.

[57] *Id.* at 24,870.

[58] *Id.* at 24,871.

[59] *Id*.

[60] EPA’s 2020 NEI Supporting Data and Summaries reported at total of 245.25 tpy for total non-Hg metal HAP emissions (sum of Selenium, Manganese, Chromium III and VI, Nickel, Lead, Arsenic, Cobalt, Antimony, Beryllium, and Cadmium emissions) for coal- and oil-fired EGUs.

[61] EPA’s 2020 NEI Supporting Data and Summaries reported at total of 2,136.96 tpy of total non-Hg metal HAP emissions for all sectors.

[62] *Id.* at 24,870. The calculated cost-effectiveness ratio in terms of dollars per ton of fPM reduced would be $37,300-44,900 per ton.

0.010 lb/MMBtu in 10 out of 20 quarters, so clearly, such a unit would need to upgrade control equipment to meet the proposed standard consistently. Moreover, no reasonable operator would operate a unit so as to exactly meet the applicable limit; there must be a compliance margin. As the Industry Study explains, EPA itself has previously acknowledged compliance margins of at least 20-30 percent.[63] Here, the combination of a very low fPM standard and having to account for measurement uncertainty and correlation methodology for PM CEMS would likely necessitate an "operational target limit" of 50 percent of the applicable limit[64] – i.e., a compliance margin of 50 percent, as EPA seems to recognize in the docket. Even using EPA's unrealistic "baseline fPM rates" and the lowest possible compliance margin of 20 percent, the Industry Study estimates that 37 units – almost twice as many as EPA's estimate – would be required to take substantial action to comply with the proposed standard.[65]

Second, while EPA's estimates for the costs of most control upgrades are generally reasonable (e.g., minor and typical ESP upgrades; fabric filter bag replacements; fabric filter replacements), PGen believes EPA has substantially underestimated the cost of the control upgrades that would be required for most of the 20 units that EPA estimates would have to take action to meet the proposed standard of 0.010 lb/MMBtu – i.e., ESP rebuild. EPA estimates an ESP rebuild would cost $75-$100/kW. The Industry Study looked at four real-world ESP rebuild projects. The costs of three out of the four projects exceed the high end of EPA's range, with two at almost twice that amount (i.e., about $200/kW). Based on the four real-world ESP rebuilds, the mean cost is $133/kW. The cost-effectiveness ratio, based on EPA's unrealistically low "baseline fPM rates" but adjusting for a minimum compliance margin of 20 percent and a mean cost for ESP rebuilds of $133/kW, would increase from a maximum of $14,700,000 estimated by EPA to about $22,000,000 per ton of total non-Hg metal HAP removed.[66]

Finally, even assuming that EPA's unrealistically low cost-effectiveness ratio is correct, EPA's proposal to revise the fPM standard to 0.010 lb/MMBtu based on cost-effectiveness of up to $14.7 million per ton of total non-Hg metal HAP removed (equivalent to $44,900 per ton of fPM removed) is inconsistent with EPA's prior actions. The cost-effectiveness ratio that EPA says in this proposal is acceptable is substantially higher than the cost-effectiveness ratio the Agency has previously found to be decidedly *not* cost-effective. EPA uses the cost-effectiveness ratio as a tool to compare against cost-effectiveness values from other proposed regulations in determining reasonableness.[67] In the past, EPA has decided against revising fPM (which is typically used as a surrogate for non-Hg metal HAPs) standards based on cost-effectiveness ratios substantially lower than the cost effectiveness here.

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[63] Industry Study, at 13.

[64] EPA, MEMORANDUM FROM BARRETT PARKER PM CEMS RANDOM ERROR CONTRIBUTION BY EMISSION LIMIT, at 2 (2023) (Docket ID No. EPA-HQ-OAR-2018-0794-5786).

[65] Industry Study, at A-1.

[66] *Id.* The calculated cost-effectiveness ratio in terms of dollars per ton of fPM reduced would increase from a maximum of $44,900 per ton estimated by EPA to about $67,300 per ton.

[67] *See* National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills, 82 Fed. Reg. 47,328, 47,336 (final Oct. 11, 2017) (comparing whether cost-effectiveness of the proposed recovery furnace emission control option was within the range of other recent EPA regulations).

For example, in EPA's technology review for the Petroleum Refinery Sector, the Agency considered a lower fPM emission standard for existing fluid catalytic cracking units.[68] EPA found that lowering the standard would cost more than $10 million per ton of total non-Hg metal HAP reduced (in that case, equivalent to $23,000 per ton of fPM reduced). The Agency decided against revising the standard because it was *not* cost-effective.[69]

In the Iron Ore Processing technology review, EPA considered revising the non-Hg metal HAP standard but found that implementing wet scrubbers incurred a cost-effectiveness of $16 million per ton of non-Hg metal HAP. The Agency decided against revising the standard because it was *not* cost-effective.[70]

In the Integrated Iron and Steel Manufacturing Facilities technology review, EPA contemplated a standard that would require upgrading all fume/flame suppressants at blast furnaces to baghouses to control non-Hg metal HAP emissions.[71] EPA found the proposed standard would cost $7 million per ton of non-Hg metal HAP reduced and concluded that the controls were *not* cost-effective.[72]

In considering beyond-the-floor MACT for Portland Cement Manufacturing, an evaluation that also considers cost-effectiveness, EPA decided against imposing a more stringent non-Hg metal HAP standard because it resulted in "significantly higher cost-effectiveness for PM than EPA has accepted in other NESHAP."[73] EPA noted in that rulemaking that it had previously "reject[ed] $48,501 per ton of PM as not cost-effective for PM."[74]

In short, even though EPA has substantially underestimated the cost-effectiveness ratio of the proposed standard of 0.010 lb/MMBtu due to the errors and incorrect assumptions in this rulemaking, as discussed above, the cost-effectiveness EPA calculated amounts to an eye-popping $12.2 to $14.7 million per ton of non-Hg metal HAP reduced. These cost-effectiveness values are higher than several cost-effectiveness values the Agency has previously determined were not acceptable. EPA should follow these precedents and acknowledge that the proposed $12.2 to $14.7 million per ton of non-Hg metal HAP reduced is *not* cost-effective. The Agency should not finalize the proposed standard of 0.010 lb/MMBtu for that reason. By the same token,

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[68] Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards, 80 Fed. Reg. 75,178, 75,201 (final Dec. 1, 2015).

[69] *Id*.

[70] National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing Residual Risk and Technology Review, 84 Fed. Reg. 45,476, 45,483 (final Jul. 28, 2020).

[71] National Emission Standards for Hazardous Air Pollutants: Integrated Iron and Steel Manufacturing Facilities Residual Risk and Technology Review, 85 Fed. Reg. 42,074, 42,088 (final Jul. 13, 2020).

[72] *Id*.

[73] National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants, 78 Fed. Reg. 10,006, 10,021 (final Feb. 12, 2013).

[74] *Id.* (citing 76 Fed. Reg. 15,704 (Mar. 21, 2011)).

the alternative, more stringent standard of 0.006 lb/MMBtu is even more grossly not cost-effective. At a cost-effectiveness of $25.6 million per ton of non-Hg metal HAP reduced, the alternative standard of 0.006 lb/MMBtu should not even be considered.

We note that EPA also includes in the record cost-effectiveness values "based on allowable" emissions that are, of course, lower than the relevant, actual cost-effectiveness values discussed above.[75] EPA says it included these values for the following reason:

> Because this cost-effectiveness evaluation [i.e., that based on *actual* emission performance and expected reductions and cost] only considers improved fPM control needed at a few units and not the entire fleet, we also evaluated an alternative cost-effectiveness approach that considers allowable emissions, assuming emission reductions achieved if all evaluated EGUs emit the maximum allowable amount of fPM (*i.e.,* at the current standard of 3.0E–02 lb/MMBtu), and the associated costs for EGUs to comply with the three potential fPM standards.[76]

That is a non sequitur. All the more so, given that here EPA candidly concedes: "This cost-effectiveness approach using allowable emissions *is not comparable* to the standard methodology used in section 112 rulemakings."[77] These cost-effectiveness numbers – based on counter-factual imaginary reductions in fPM/non-Hg metal HAPs from an imaginary situation in which every EGU in EPA's database is operating at the current 0.030 lb/MMBtu fPM limit and thus their reductions at zero cost are nonetheless attributable to the proposed revised standard – are not otherwise used or discussed in the rulemaking. For good reason, as they are irrelevant and by the Agency's own admission, "not comparable" to the standard methodology used in all previous RTR as well as beyond-the-MACT-floor rulemakings. What they seem to be, however, is a tacit, further concession by EPA that the *actual* cost-effectiveness values for this Proposed Rule, which *are* comparable to the methodology used in section 112 rulemakings, are so much higher than values EPA has previously found to be not cost-effective, that EPA found it useful to float irrelevant, but lower cost-effectiveness values based on "allowable" emissions. Any reliance by EPA on the latter imaginary cost-effectiveness values, contrary to the standard methodology heretofore used in section 112 rulemakings, would be arbitrary and capricious.

C. EPA Correctly Declined to Propose the 0.006 lb/MMBtu Standard and Should Not Adopt It.

PGen supports EPA's decision declining to propose the 0.006 lb/MMBtu standard,[78] and we urge the Agency not to adopt such a low standard. As an initial matter, EPA has not properly justified the proposed 0.010 lb/MMBtu standard, as explained above. The reasons undermining that proposed standard apply with even greater force to the lower 0.006 lb/MMBtu standard.

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[75] 88 Fed. Reg. at 24,870.

[76] *Id.*

[77] Technology Review Memo, at 12 (emphasis added).

[78] 88 Fed. Reg. at 24,871 ("The EPA declines to propose 6.0E-3 lb/MMBtu as the primary policy option here in light of … potential costs, including EPA's current assessment of measurement uncertainty, when considering the current fleet.").

We agree with EPA that the 0.006 lb/MMBtu standard creates a host of obstacles, making the standard unrealistic to implement, such as cost-effectiveness and PM CEMS measurement uncertainty and correlation (discussed further, in connection with the proposed 0.010 lb/MMBtu standard, in section V, below).[79] Moreover, as outlined in subsection A above, the variability of quarterly data – which we believe EPA must consider in adopting any revised standard in this rulemaking – would demonstrate that the majority of EGUs would exceed the 0.006 lb/MMBtu standard. In turn, the 0.006 lb/MMBtu standard would require considerable investment for many coal-fired EGUs to install additional emission controls.

Even taking EPA's "baseline fPM rates" at face value, EPA estimates that the 0.006 lb/MMBtu standard would affect 65 EGUs, reducing a mere 24.7 tpy of non-Hg metal HAPs to the tune of $633 million annually.[80] EPA estimates the lower standard would result in additional coal-fired EGU premature retirements of 11,300 MW, creating additional substantial risk to electric grid reliability.[81] EPA estimates compliance costs of meeting the 0.006 lb/MMBtu standard from 2028 through 2037 would increase to $4.27 billion (from $330 million for the proposed 0.010 lb/MMBtu standard).[82] EPA's own cost-effectiveness of $25.6 million/ton of total non-Hg metal HAP reduced for the 0.006 lb/MMBtu standard is twice the cost-effectiveness EPA calculated for the proposed 0.010 lb/MMBtu standard, which itself exceeds all prior non-Hg metal HAP cost-effectiveness values that EPA readily determined were too high to justify revision of the standard. As the Industry Study shows, accounting for even a very modest compliance margin for a revised standard of 0.006 lb/MMBtu would increase the number of affected units to 75, at a whopping cost-effectiveness value of $92,470,000 per ton of total non-Hg metal HAP reduced.[83]

D. The Proposed fPM Standard of 0.010 lb/MMBtu and the Alternative Standard of 0.006 lb/MMBtu Would Likely Lead the Vast Majority of EGUs that Require Significant Control Upgrades to Shut Down.

EPA estimates, based on unrealistically low "baseline fPM rate" and without accounting for compliance margin, that certain EGUs will require major control equipment installation (fabric filters for the Colstrip units) or upgrades (ESP rebuilds for certain other EGUs with baseline fPM rates higher than 0.010 lb/MMBtu) to meet the proposed standard of 0.010 lb/mmBtu. EPA also underestimates the cost of such major ESP upgrades. Even putting these major flaws aside, based on EPA's own identification of units that would require major controls, and assuming the cost of ESP rebuilds at $100/kW, the capital cost of these controls would range from $41.7 million (for

[79] *Id.*

[80] *Id.* at 24,870.

[81] EPA, 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 3-14 (2023).

[82] 88 Fed. Reg. at 24,893 (assuming a present value with a three percent discount rate). For the reasons discussed in these comments, EPA's estimates substantially understate the likely cost of the proposed standards.

[83] Industry Study, at 21-20, Table 50-3.

the D B Wilson EGU) to $148 million (for each of the Colstrip units).[84] In its evaluation of the impact of the proposed standard, EPA claims this rule would result in only about 500 MW of shutdowns.[85] Those shutdowns, it turns out, correspond to a single unit at a West Virginia power plant, which, at $100/kW, would require an ESP upgrade with a capital cost of about $52 million.

EPA is correct that a standard that would require a capital expenditure of $52 million for a single unit would likely result in the shutdown of that EGU. The same is surely also true, however, for *all* units that would be required to expend close to $40 million and more in capital cost to upgrade control equipment as a result on the Proposed Rule. This is especially true given that EPA also has recently proposed other rules that are likely to result in a large number of coal-fired EGUs electing to shutdown by 2032.[86] In the current, uncertain climate regarding the viability of any coal-fired EGU past 2032, the Proposed Rule is likely to result in substantially more shutdowns that the mere 500 MW EPA estimated. If EPA insists on proceeding with the proposed standard, it must realistically assess the viability of these EGUs and account for their shutdown in evaluating the cost-effectiveness and impact of the Proposed rule on cost as well as the reliability of the electric grid.

It is hardly necessary to elaborate on this issue with respect to the alternative fPM standard of 0.006 lb/MMBtu. The capital cost of fabric filter construction exceeds that of major ESP upgrades significantly. Given the economic *and* regulatory climate (including the proposed ELG and Section 111(d) proposals), a revised standard that would require the installation of a fabric filter on an EGU that currently has no such controls would surely doom such a unit to shutdown. The premature shutdown of a minimum of 52 EGUs by mid-2027 would increase the cost of this Proposed Rule substantially and would have a devastating effect on reliability.

IV. EPA SHOULD RETAIN STANDARDS FOR INDIVIDUAL, OR AT LEAST TOTAL, NON-HG METAL HAPS

EPA should not remove the individual and total non-Hg metal HAP limits. Although, PGen agrees that fPM is a suitable surrogate for non-Hg metal HAPs, and thus EPA was and is justified in setting a standard for fPM under MATS, it is incongruous for EPA to eliminate the standards for the pollutants that are actually the subject of Section 112 – the non-Hg metal *HAPs*. EPA offers no substantive reason for eliminating the actual HAP standards.

As an initial matter, although a few EGU owners have chosen to demonstrate compliance with the non-HG metal HAP standards, these EGUs presumably selected that for a reason. No matter

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[84] Industry Study, at App. A, Table A-1.

[85] 88 Fed. Reg. at 24,889.

[86] *See, e.g.,* Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 88 Fed. Reg. 18,824 (proposed Mar. 29, 2023); New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33,240 (proposed May 23, 2023).

how justified a surrogate is, there will be situations in which the underlying HAP – the pollutant of real interest – may not follow the generally applicable correlation between the HAP and the surrogate that the fPM standard is based upon. For that reason, EPA should retain the flexibility for EGUs to meet either the fPM or individual/total non-Hg metal HAP standards.

Second, removing the individual and total non-Hg metal standards untethers the reduction of non-Hg metal HAP standards from the fPM emission limits. The purpose of revising a HAP standard under Section 112(d)(6) is to further regulate *HAPs* from the source category. Here, removing the individual and total non-Hg metal standards appears to confirm that the purpose of *this* Proposed Rule under Section 112(d)(6) is, in truth, to effect reductions in fPM, regardless of any reductions in the pollutants of interest – the HAPs. Indeed, EPA's economic analysis of the rule relies solely on purported benefits from the reduction of PM, and does not even bother to quantify the benefits of further non-Hg metal HAP reductions.

If EPA finalizes any revised standards under this Proposed Rule, we urge EPA to retain the non-Hg metal HAP standards.

V. EPA'S PROPOSAL TO ELIMINATE QUARTERLY STACK TESTING AS THE COMPLIANCE METHOD FOR THE fPM SURROGATE STANDARD IS PROBLEMATIC, ESPECIALLY IF THE fPM STANDARD IS REDUCED BY TWO-THIRDS.

A. Proper Correlation of PM CEMS at the Proposed fPM Surrogate Emission Standard of 0.010 lb/MMBTU Is Next to Impossible.

EPA's proposal to require the use of PM CEMS for all coal-fired EGUs to demonstrate compliance with the proposed fPM surrogate standard of 0.010 lb/MMBtu glosses over significant technical challenges. Indeed, as Ralph L. Roberson, an engineer with more than 50 years of experience with the regulation and monitoring of emissions from EGUs and other facilities, explains in the attached technical memorandum, this very low standard would require correlation over such a limited data range that it would be "virtually impossible" to establish a valid correlation of the PM CEMS.[87]

The Roberson Memo explains that PS-11, EPA's performance specification for correlation testing, requires a minimum of 15 test runs using MATS Method 5, spaced over three distinct PM concentration ranges (i.e., low, mid and high) that span the expected range of emissions from EGUs. PM CEMS concentrations in correlation testing are expressed in milligrams per actual cubic meter (mg/acm), with 0.010 lb/MMBtu equivalent generally to a concentration of about 7.5 mg/acm.[88] For an emission limit equivalent to 7.5 mg/acm, the low range is 0 to 3.75 mg/acm; the mid range is 1.88 to 5.63 mg/acm; and the high range is 3.75 to 7.5 mg/acm. EPA suggests operators can achieve these very small ranges of fPM concentrations by "varying process operations, varying fPM control device conditions, and PM spiking zero point methods when

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[87] RALPH L. ROBERSON, MEMORANDUM, TECHNICAL COMMENTS ON EPA'S PROPOSED RULE: MERCURY AND AIR TOXICS STANDARDS RISKS AND TECHNOLOGY REVIEW, at 3 (2023) [hereinafter PM CEMS Technical Memo] (Attachment C to these comments).

[88] *Id.* at 2.

previous techniques cannot provide the 3 distinct concentration levels."[89] That is completely unrealistic, and indeed next to impossible.[90]

The problem of a limited data range over very low fPM concentrations is further compounded by measurement uncertainty – and there is always uncertainty, for any measurement technique, from the reference method as well as the instrument itself, among others – which here would be too large compared to the limited range of fPM concentrations in the correlation testing.[91] As the PM CEMS Technical Memo explains, PS-11 specifies certain statistical criteria for the correlation to account for the uncertainties inherent in measuring PM concentrations.[92] For the fPM concentration of 7.5 mg/acm (equivalent to the proposed fPM standard of 0.010 lb/MMBtu),

> the 95% confidence interval would have to be less than or equal to 0.75 mg/acm. Likewise, the tolerance interval would have to be less than or equal to 1.88 mg/acm. We are not aware of any data or technical support that any commercially available PM CEMS is capable of meeting these very tight confidence and tolerance intervals, and EPA cites none. Adding to the challenge of achieving these strict confidence and tolerance intervals is the fact that these intervals will be at or near the method detection limit of the EPA Method 5, even with extended run times.[93]

EPA claims that extending the test run times to 3 hours would resolve any uncertainty issues associated with the reference method (i.e., MATS Method 5). PGen is concerned that the 3-hour runs may have detrimental impacts on some FGD control devices. For example, one PGen member operates two plants that use Jet Bubble Reactors, which achieve very high fPM control efficiencies. However, Jet Bubble Reactors are also sensitive to fly ash carryover, which can impair FGD effectiveness and ultimately fPM control efficiencies. This could have a major impact on Jet Bubble Reactor operation during the 3-hour long detuned test runs that would be necessary to establish a valid correlation curve. Moreover, conducting up to 20 test runs of 3 hours duration each would require on the order of 2 weeks and would thus be extremely costly and unrealistic to maintain.[94] Putting aside these concerns, however, mitigating the impact of reference method uncertainty (by conducting 3-hour test runs, as EPA claims) does nothing to address other uncertainties, including the uncertainties inherent in the measurement device, and it does not in any way resolve the problems associated with relative size of the uncertainty to the limited data range of fPM concentrations and the confidence levels and tolerances discussed above.

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[89] 88 Fed. Reg. at 27,874.

[90] PM CEMS Technical Memo, at 3 ("Anyone who believes he or she can regulate and control PM emissions from a coal-fired EGU that precisely has never set foot in such a facility.").

[91] *Id.* at 4.

[92] *Id.*

[93] *Id.* at 5.

[94] *Id.* at 3 ("This is an excessive amount of time to take a unit off dispatch and hold constant load conditions for the sake of testing.").

EPA in the past agreed, as evidenced by its decision in the "Portland Cement NESHAP from 10 years ago (*see* 77 FR 42374, July 18, 2012)," which the Agency acknowledges in the Proposed Rule.[95] EPA's rationale for rejecting PM CEMS as the compliance method for a very low, proposed fPM standard (very similar in terms of fPM concentrations to the proposed standard in the Proposed Rule) is almost the same as that presented above and in the PM CEMS Technical Memo:

> A particular challenge in applying PM CEMS to source emissions monitoring is in measuring the very low PM concentrations associated with a low applicable emissions limit for PM precisely enough to meet the PS 11 correlation requirements. In addition to measurement uncertainty inherent in PM CEMS data, the measurement uncertainty associated with the reference test method (e.g., Method 5) is a significant contributor to successful development of a PM CEMS correlation regardless of the type of PM CEMS used.
>
> As noted above, PS 11 specifies acceptable criteria for a correlation directly related to the applicable emissions limit. The Portland cement NESHAP PM emissions limit for existing sources of 0.04 lb/ton of clinker equates to 5 to 8 mg/dscm …. For a PM CEMS set up to measure compliance with a 5 to 8 mg/ dscm equivalent limit, the inherent uncertainty associated with a 1 hour Method 5 measurement (±0.6 to 1.2 mg/ dscm) would constitute more than half of the ±5 percent of the applicable PS 11 acceptance threshold (i.e., ±1.2 to 2.0 mg/dscm) of the mid-level PS 11 correlation test (i.e. the correlation for the middle of the three PS 11 correlation points).
>
> Although one can improve the method detection capabilities of the Method 5 or other filterable PM test method by increasing sampling volume and run time, uncertainties in measurement would remain. For example to achieve a practical quantitation limit of 1 mg/dscm, one would need to conduct a test run of 6 hours or longer. The measurement uncertainty associated with a 6-hour Method 5 test runs at this concentration would be ±0.01 to 0.2 mg/dscm. At this level, the uncertainty associated with the PM test method measurements alone would be about half of the correlation limit allowed in PS 11. The PS 11 correlation calculations would also have to account for any PM CEMS measurement uncertainty.[96]

In the passage above, EPA acknowledges – indeed relies on – the same technical concerns that the Roberson Memo details, and the Agency recognizes explicitly that even 6-hour test runs would not be sufficient to alleviate the problems arising from the size of measurement uncertainty relative to the very limited data range associated with a very low proposed fPM standard.

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[95] *See* 88 Fed. Reg. at 24,873.

[96] 77 Fed. Reg. 42,368, 42,374-75 (Jul. 18, 2012).

Ignoring the above reasoning, EPA attempts to dismiss the import of its decision to eliminate PM CEMS for compliance in the Portland Cement rulemaking by noting that the particle characteristics of the two source categories (Portland cement manufacturing facilities and EGUs) are different. That difference is not in any way relevant to the problem identified in the PM CEMS Technical Memo and by EPA itself in the Portland Cement rulemaking in the passage quoted above.[97] The problem is that the proposed standard is so low that the relative size of the testing and measurement uncertainties, even if one component of them is minimized by longer test runs, creates an insurmountable barrier to valid correlation as required under PS-11.

EPA's additional arguments in support of its proposal to require PM CEMS for compliance with a proposed fPM limit of 0.010 lb/MMBtu are unavailing. EPA first argues that PM CEMS for the proposed fPM limit must be feasible, since MATS already requires PM CEMS for new coal-fired EGUs (i.e., EGUs that are constructed after 2012) for a new-unit fPM standard of about 0.009 lb/MMBtu.[98] But this is no support at all, not in the real world. There have been no new coal-fired EGUs constructed since MATS was promulgated. And EPA knows full well there will never be such EGUs.[99] So the fact that MATS had a theoretical requirement for new EGUs that was never demonstrated in the real world and that EPA acknowledged in a previous rulemaking is not feasible provides no support to EPA's argument.

Second, EPA claims that sources can use a Qualitative Aerosol Generator ("QAG") – an instrument that the Electric Power Research Institute ("EPRI") had tried to develop in the past – to control fPM concentrations for correlation testing.[100] As the PM CEMS Technical Memo notes, however, that work was never completed, in large part because EPA never showed any interest in it. There are no QAGs for anyone to use. It is ironic that EPA relies on a defunct project – abandoned primarily because EPA showed no interest in it – to support its PM CEMS proposal.[101]

Finally, EPA's assertion that the cost of using PM CEMS for compliance is less than using quarterly testing cannot be true. Utilities are rational economic actors, indeed they may be some of the most rational economic actors anywhere for the simple reason they are required to be so under public utility regulations. It does not stand to reason that "not all (indeed, only a minority

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[97] *See* PM CEMS Technical Memo, at 3-4 (We agree that the particle characteristics may indeed be different; however, 5 to 8 mg/dscm is a low PM concentration regardless of the size, shape, or constituency of the particles.).

[98] 88 Fed. Reg. at 24,874.

[99] EPA concedes as much in the Proposed Rule. *See id.* at 24,858 ("The EPA is unaware of any new coal- or oil-fired EGUs in development and has not projected any new coal- or oil-fired EGUs in EPA modeling to support various power sector-related rulemakings. For that reason, the EPA has not reviewed and is not proposing any revisions to the MATS new source emission standards."). Similarly, in its recent proposal revising, among others, the New Source Performance Standard (NSPS) for existing coal-fired EGUs, EPA explains that it is not revising the NSPS for new coal-fired EGUs "because the EPA does not anticipate that any such units will construct or reconstruct and is unaware of plans by any companies to construct or reconstruct a new coal-fired EGU." 88 Fed. Reg. 33,245 (May 23, 2023).

[100] 88 Fed. Reg. at 24,874.

[101] PM CEMS Technical Memo, at 6.

of about one third) EGU owners or operators chose the most cost-effective means of demonstrating compliance with the fPM emission limits."[102] This alone ought to clue EPA that its PM CEMS versus quarterly stack test cost comparison is wrong. That cost analysis also does not account for the extended correlation testing periods that would be required if sources must undertake 3-hour test runs over a two-week period.

The PM CEMS Technical Memo reports an estimated 10-year cost for PM CEMS of $479,500, without accounting for spiking or 3-hour test runs. This is much higher than EPA's estimates.[103] Mr. Roberson also obtained a cost estimate of $38,000 from a stack testing company to conduct four quarterly stack tests and collect a minimum sample volume of 4 dscm for each run. This is substantially lower than EPA's cost estimates.[104]

In short, EPA appears to have underestimated the cost of PM CEMS and inflated the cost of quarterly testing to reach the counter-factual and illogical conclusion that the majority (about two thirds) of "EGU owners or operators [did not choose] the most cost-effective means of demonstrating compliance with the fPM emission limits."[105] If that were true (that PM CEMS are the most cost-effective option), EPA need not require PM CEMS as the only compliance method for fPM in this rulemaking. Rational economic actors would choose it.

B. EPA Should Exclude from PM CEMS Requirements EGUs that will Retire Consistent with the December 31, 2028 Retirement Option of the ELG Rule.

If EPA insists on requiring PM CEMS for compliance notwithstanding the very substantial technical – indeed infeasibility – issues and the cost differential between PM CEMS and quarterly stack testing discussed above, PGen requests that EPA exclude at least those units that have committed to retire by December 31, 2028 under the ELG Rule.[106] It simply makes no sense to impose these costs and uncertainties on units that would operate no more than one year after the effective date of the proposed PM CEMS requirement. Nor would it be appropriate to upend resource adequacy planning by causing currently scheduled retirements to advance their shutdown dates because of a monitoring requirement that is reflective of an EPA preference, not a defined need.

VI. EPA CORRECTLY CONCLUDED THAT THE Hg STANDARD FOR NON-LIGNITE-FIRED EGUS SHOULD NOT BE REVISED.

PGen agrees with EPA's proposal to retain the Hg emission standard of 1.2 lb/TBtu for non-lignite-fired EGU units.[107] EPA based this decision primarily on the fact it lacks detailed

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[102] 88 Fed. Reg. at 24,872; PM CEMS Technical Memo, at 5 (describing this EPA quote to be "as insulting as it is incorrect.").

[103] PM CEMS Technical Memo, at 6.

[104] *Id*.

[105] 88 Fed. Reg. at 24,872; PM CEMS Technical Memo, at 5 (describing this EPA quote to be "as insulting as it is incorrect.").

[106] Steam Electric Reconsideration Rule, 85 Fed. Reg. 64,650, 64,679, 64,710 (Oct. 13, 2020).

[107] 88 Fed. Reg. at 24,879.

information about control configurations and efficiencies. Also clear, EPA did not identify any developments in practices, processes, and control technologies that would justify revising the Hg standard for non-lignite-fired EGUs under Section 112(d)(6).

Available Hg emissions do not provide a basis for revising the current Hg standard. EPA reports bituminous coal-fired and subbituminous coal-fired EGUs achieve an average annual Hg rate of 0.4 lb/TBtu and 0.6 lb/TBtu, respectively.[108] But compliance under MATS is based on neither an average rate among EGUs, nor on an annual rate. Compliance is based on 30-day rolling rate for each EGU. Accordingly, EPA's data about average annual performance is not relevant to the standard at issue. These data do not account for the variability in Hg emission rates between EGUs and on day-to-day and month-to-month basis for each EGU. That variability is driven by myriad factors, and strongly supports retaining the current Hg standard for non-lignite coal-fired EGUs.

The attached Industry Study contains data that support retaining the current Hg standard. Indeed, even looking at annual average rates, analyses of the 2018 data show that the sum of the annual average with the standard deviation, which is the range of variability in the data, approaches the current 1.2 lb/TBtu standard.[109] In addition, PGen offers the following observations that highlight the vast variability in factors that affect Hg emissions. First, the variability in Hg content of non-lignite coals, for both bituminous and subbituminous coals, is considerably broader than EPA suggests in the proposed Rule.[110]

Second, the variability in process conditions for Hg removal (i.e., sorbent composition, sorbent injection rates, co-benefits, and re-emission) is also broad and does not support further lowering Hg standard for non-lignite-fired EGUs. Sorbent injection plays a critical role in removing Hg emissions from bituminous and subbituminous coal-fired EGUs. EPA correctly points out that increasing sorbent injection rates generally increases Hg removal but with diminishing returns as more sorbent is added.[111] For example, research tests at Ameren's Labadie Unit 3 explored the effectiveness of conventional activated carbon, brominated active carbon, and conventional activated carbon for Powder River Basin ("PRB") subbituminous coal. Results show that increasing sorbent rates of any of the three materials could only reach a control maximum of 90 percent removal.[112] Consequently, it is not at all assured that an EGU that relies on sorbent injection for Hg control could increase its Hg removal efficiency simply by increasing the amount of sorbent used.

Moreover, the co-benefits of SCRs and FGDs are highly variable. PGen is unaware of actions that could be taken to improve the co-benefit removal efficiency of particular equipment installed at a particular EGU. Emission control efficiencies are further potentially undermined by re-emission of Hg from wet FGD. Uncaptured Hg in wet FGD may be re-released in solution

[108] *Id.*

[109] *Id.*

[110] Industry Study, at 36.

[111] 88 Fed. Reg. at 24,879.

[112] Industry Study, at 40.

during the blowdown stage, precipitated and released as an unintended byproduct, or reduced from an oxidized state and re-enter the flue gas.[113] Upsets in wet FGD can also reduce the collection efficiency and re-emit Hg emissions.

Finally, Hg control efficiencies are further impacted by variability in electricity loads. An in-plant study, for example, found that loss of oxidation/reduction potential control, known to vary over load cycles, results in Hg re-emissions.[114] Little, if anything, can be done to mitigate control efficiency variability due to load variability.

PGen acknowledges that EPA has solicited comments on its proposed decision not to revise the Hg standard for non-lignite-fired EGUs and requested information that could possibly support a revised standard. PGen is unaware and does not believe such information exists. In any event, if additional information submitted to EPA leads the Agency to consider a revised Hg standard for non-lignite coal-fired EGUs, PGen respectfully suggests (and requests) that EPA must first propose such a revised standard in a Supplemental Notice of Proposed Rulemaking or a separate Notice of Proposed Rulemaking and take comment on such a proposed standard before adopting it.[115]

VII. EPA CORRECTLY CONCLUDED THAT OTHER HAP STANDARDS (I.E., ACID GASES; ORGANIC HAPS) SHOULD NOT BE REVISED.

PGen agrees with EPA that no revisions to the standards for Organic HAP and Acid Gas are necessary.[116] EPA found that there are no new developments that would result in cost-effective emission reductions for Organic HAPs. PGen agrees. PGen too is unaware of any new cost-effective practices, processes, or control technologies that would warrant revising the Organic HAP emission standards. Similarly, PGen members agree with EPA that the Agency has not identified any cost-effective improvements that would result in further acid-gas emission reductions.

PGen acknowledges that EPA has solicited comments on its proposed decision not to revise these standards and requested information that could possibly support a revised standard. PGen is unaware and does not believe such information exists. In any event, if additional information submitted to EPA leads the Agency to consider revised standards for acid gases or organic HAPs, PGen respectfully suggests (and requests) that EPA must first propose such revised standards in a Supplemental Notice of Proposed Rulemaking or a separate Notice of Proposed Rulemaking and take comment on such proposed standards before adopting them.[117]

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[113] *Id.* at 40-41.

[114] *Id.*

[115] *See, e.g.,* EPA, FERROMANGANESE AND SILICOMANGANESE PRODUCTION: NATIONAL STANDARDS FOR HAZARDOUS AIR POLLUTANTS RULE HISTORY, https://www.epa.gov/stationary-sources-air-pollution/ferromanganese-and-silicomanganese-production-national-emission (last visited on May 31, 2023) (showing that supplemental notice of proposed rulemaking to notify affected sources of a revised technology review and proposing additional emission standards for comment.).

[116] 88 Fed. Reg. at 24,882.

[117] *See* EPA, *supra* note 115.

VIII. EPA'S RATIONALE FOR REVISING THE HG STANDARD FOR LIGNITE EGUS IS FLAWED: THE DIFFERENCES BETWEEN LIGNITE AND PRB SUBBITUMINOUS COALS RESULT IN SUBSTANTIALLY DIFFERENT Hg REMOVAL EFFECECTIVENESS FOR SORBENT INJECTION.

EPA's proposal to revise the Hg standard for lignite-fired EGUs substantially to 1.2 lb/TBtu (the same standard applicable to bituminous and subbituminous coal-fired EGUs) is flawed because it is based on a premise that is plainly erroneous. Revising this standard on the basis of premise that runs counter to the data before the Agency would be arbitrary and capricious.

The fundamental premise of EPA's proposed revisions to the Hg standard for lignite-fired EGUs is that lignite coal and sub-bituminous PRB coal have similar Hg content, halogen content, and alkalinity, and that therefore "it is difficult to justify why those units should not meet a similar level of Hg control."[118] This conclusion is wrong, because despite some similarities, the *differences* between lignite and sub-bituminous PRB coal result in very different Hg removal performance for the main Hg control technology available for lignite-fired EGUs – halogenated activated carbon sorbent injection. We discuss these differences, below.

A. EPA Failed to Consider the Variability of Hg in Lignite Coal.

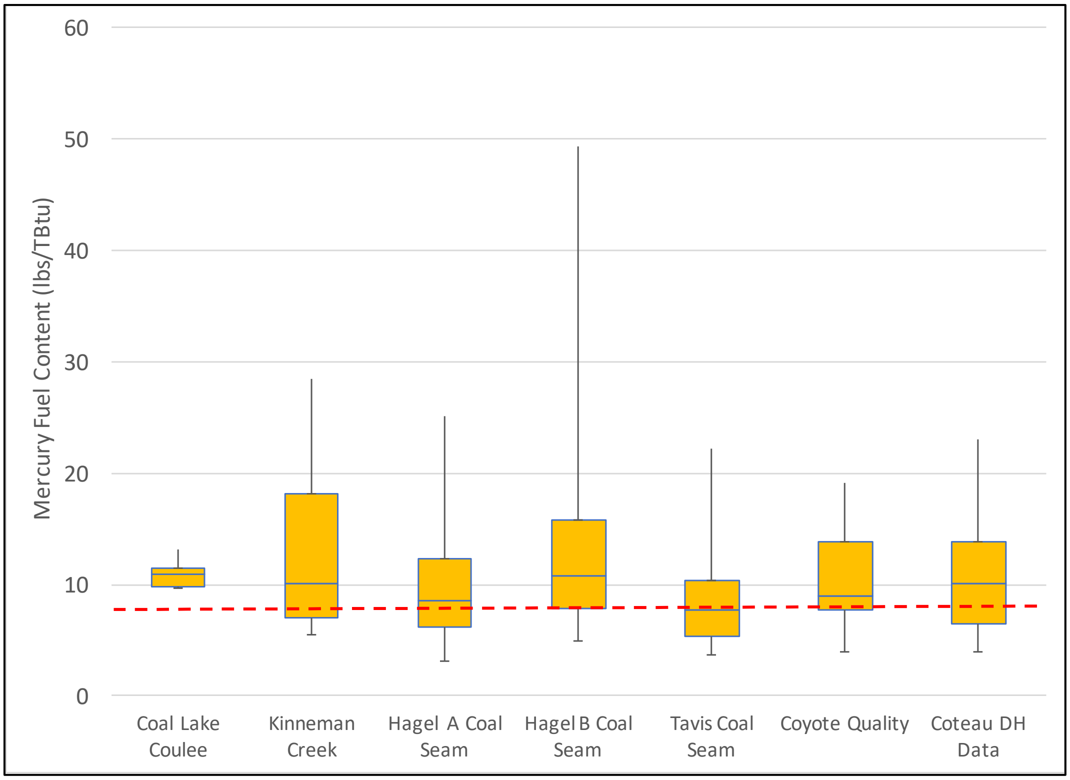
EPA's proposal to lower the Hg standard for lignite-fired EGUs ignores the complete chemical composition of lignite-coal and technical challenges in Hg control technologies for EGUs firing lignite coal. EPA ignores the wide variability of Hg content, sulfur content, and alkalinity of inorganic matter in Fort Union (North Dakota) and Gulf Coast Lignite.

EPA assumes an average Hg content for Fort Union lignite of up to 7.8 lb/TBtu.[119] That assumption is not supported by any test data – EPA's analysis relies solely on the Integrated Planning Model ("IPM") assigned inlet Hg content value of 7.81 to derive an 85 percent Hg control rate to meet a 1.2 lb/TBtu standard.[120] As shown in the figure below, actual chemical composition tests for lignite from Fort Union mines in North Dakota show a substantial Hg content variability within each mine.

[118] 88 Fed. Reg. at 24,881.

[119] *Id*.

[120] *Id*. at 24,879.



Mercury Content Variability for Eight Lignite Suppliers in North Dakota[121]

The data reported in the figure above also show how high the Hg content of North Dakota lignites typically is: the 75th percentile of data from each lignite supplier significantly exceeds EPA's value of 7.8 lb/TBtu by a substantial margin. For one North Dakota lignite mine, the 75th percentile Hg content is upwards of 18 lb/TBtu, more than double EPA's assumption.[122] Based on these actual Hg content data for North Dakota lignite mines, achieving a 1.2 lbs/TBu requires an Hg removal rate of approximately 93-95% for unavoidable instances where lignite Hg content is at the 95th percentile of observed values.[123] Such high removal efficiencies cannot be achieved by sorbent injection. And, they certainly cannot be achieved given the other chemical composition differences between lignite and PRB coals, as discussed in subsection B, below.

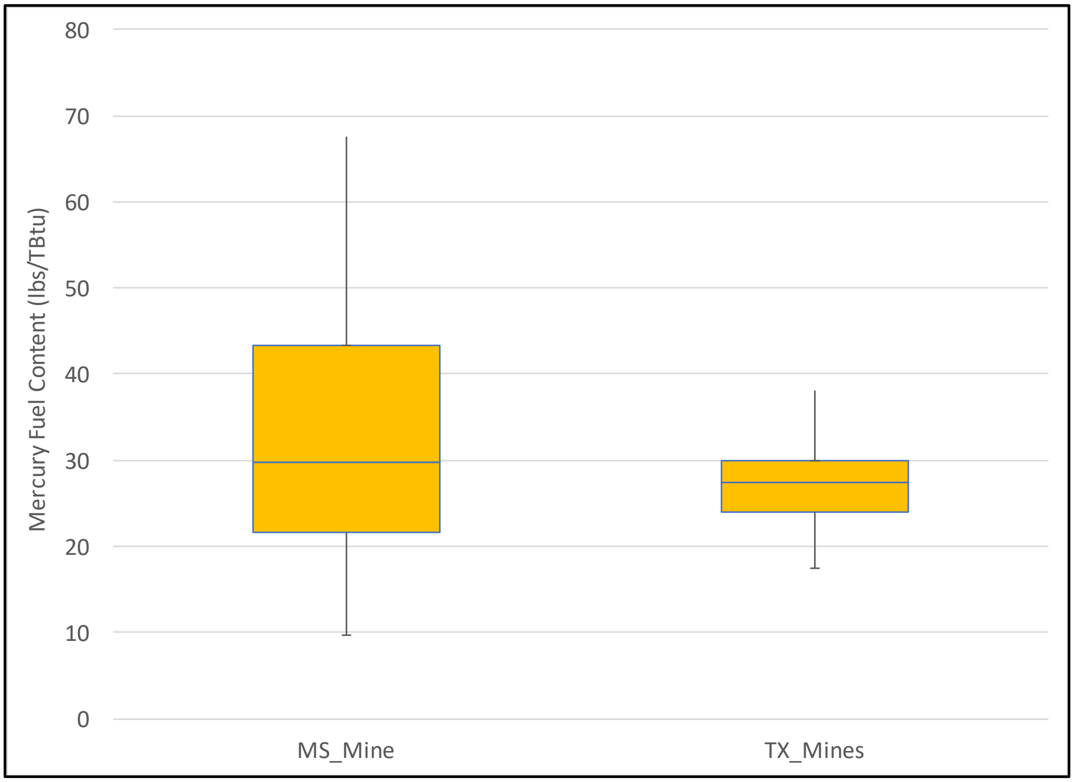
The Hg content of Gulf Coast lignite coal is even higher: the 75th percentile from Mississippi and Texas mines exceeds 40 lb/TBtu and 29 lb/TBtu, respectively, as shown in the figure below.[124]

[121] Industry Study, at 23, Fig. 6-1.

[122] Industry Study, at 23-24.

[123] *Id.* at 25.

[124] *Id.* at 27.



Mercury Content Variability for Two Gulf Coast Sources: Mississippi and Texas[125]

EPA in the Proposed Rule assigned an Hg inlet value of 12.44 to 14.88 lb/TBtu to Gulf Coast lignite, deriving a control rate ranging from 80 to 90 percent to meet the 1.2 lb/TBtu standard.[126] However, based on actual Hg content data for Gulf Coast lignite, achieving a 1.2 lbs/TBu requires an Hg removal rate of approximately 96-97% for unavoidable instances where lignite Hg content is at the 95th percentile of observed values.[127] Current Hg control technologies available for lignite-fired EGUs cannot reach these theoretical control efficiencies. As discussed in the following subsection, that is exacerbated by other chemical composition differences between lignite and PRB coals.

B. EPA Failed to Consider that Flue Gas SO_3 in Lignite-Fired EGUs Significantly Impairs Sorbent Injection Hg Control Efficiencies.

EPA focuses on the fact both lignite and PRB coals have low halogen content and produce difficult-to-control elemental Hg vapor in the flue gas stream to conclude that lignite-fired EGUs can simply increase the amount of halogenated sorbent injected to reduce Hg emissions to 1.2 lb/TBtu – a limit that PRB coal-fired EGUs are able to consistently meet.[128] EPA, however, fails to recognize very consequential differences in the chemical composition of lignite and PRB coals that result in very different Hg removal effectiveness for sorbent injection for the two coals.

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[125] Industry Study, at 27, Fig. 6-5.

[126] 88 Fed. Reg. at 24,879.

[127] Industry Study, at 29.

[128] Technology Review Memo, at 21.

Specifically, one of the most important characteristics of PRB coal is that it typically has very low sulfur content, with combustion resulting in very little – "essentially unmeasurable" – SO_3 in the flue gas. In contrast, the higher sulfur content of lignite combined with equal or lower total alkali relative to sulfur allows much higher levels of SO_3 in lignite-generated flue gas.[129]

SO_3 in the flue gas has a substantial and well-documented detrimental effect on the Hg removal effectiveness of activated carbon sorbent, the material used to capture Hg emissions.[130] Sargent & Lundy, EPA's contractor in preparing an analysis of Hg control technology, recognized the impact of SO_3 on activated carbon sorbent Hg removal effectiveness, stating "'[w]ith flue gas SO_3 concentrations greater than 5-7 ppmv, the sorbent feed rate may be increased significantly to meet a high Hg removal and 90 [percent] 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 SO_3 increase from just 5 ppmv to 10 ppmv*.'" (emphasis supplied).[131]

Additionally, flue gas SO_3 further complicates Hg removal because of operational temperature. Lignite-fired EGUs that emit measurable levels of SO_3 observe higher gas temperatures at the air heater exit.[132] The air heater exit is also the location activated carbon sorbent is injected to avoid corrosion.[133] Pilot plant studies have shown that an increase of gas temperature at the heater exit from 310°F to 340°F decreased sorbent Hg removal by 13 percent from 81 percent to 68 percent.[134]

Lignite and PRB coal are different. Taken together, these differences – the high variability of Hg content in lignite coal that would require Hg control efficiencies greater than 90 percent to meet the proposed standard; the presence of flue gas SO_3 in lignite-fired EGUs that can decrease Hg control efficiencies by half; and, challenges with balancing high temperatures at the heater exit that can further decrease Hg control efficiency up to 13 percent – make EPA's proposed Hg emission standard for lignite-fired EGUs of 1.2 lb/TBtu not achievable.

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[129] Industry Study, at 31.

[130] *Id*.

[131] *Id.* (quoting Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology (Mar. 2013)).

[132] *Id.* at 31.

[133] *Id.*

[134] *Id.* at 32.

IX. EPA SHOULD ADOPT A COMPLIANCE DATE FOR ANY REVISED STANDARDS OF THREE YEARS AFTER THE EFFECTIVE DATE OF THE FINAL RULE, AND EPA SHOULD PROVIDE FURTHER FLEXIBILITY AS IT DID IN THE ORIGINAL MATS RULE AND AS IT HAS PROPOSED IN SEVERAL RECENT RULEMAKINGS.

A. EPA Should Adopt a Compliance Date for Any Revised Standards of Three Years After the Effective Date of the Final Rule and Provide Guidance for One-Year Extensions Where Appropriate.

If EPA adopts a final rule that imposes revised standards on coal-fired EGUs, PGen requests that EPA provide a compliance date of three years after the effective date of the final rule. This period is necessary, first, to allow affected EGUs to evaluate whether additional controls will be needed to meet the revised standards (as explained earlier, EPA has substantially underestimated the number of those units in the Proposed Rule by using an unrealistic baseline fPM rate to identify EGUs that would require major control upgrades). Second, EGUs that determine major control upgrades are needed to meet the revised standards must carefully evaluate numerous financial, technical, and regulatory variables before they can decide whether affected EGUs can meet the revised standards and remain *viable*. The regulatory and economic analysis will require a significant effort to complete considering other laws and regulations that affect coal-fired EGUs such as the Inflation Reduction Act, the Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards, the proposed Greenhouse Gas Standards and Guidelines for Fossil Fuel-Power Plants, and the proposed Effluent Limitation Guidelines rulemaking, to name a few.

Third, and most importantly, after that analysis, these EGUs will need the full three years, which is common for any major upgrade or replacement of control devices in this industry, to finance, design, procure, build/modify, and effectively operate emission control and monitoring equipment to comply with the revised standards.[135]

Moreover, just as it did in the original MATS rule, EPA should anticipate that some EGUs may require significantly more effort and compliance time to meet the revised standards, and it should provide guidance in the final rule regarding one-year extensions under CAA section 112(i)(3).[136]

[135] For example, the ESPs rebuilt at AES Petersburg station in 2014, *see* Industry Study at 17 & n.20, took three years to build, with the bulk of expenditures in the third year. *See* State of Indiana – Indian Public Utility Commission, Order of the Commission, Cause No. 44242 (Aug. 14, 2013), Appendix, pdf page 50 of 51.

[136] National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 77 Fed. Reg. 9,304, 9,406-9,411 (Feb. 16, 2012).

B. EPA Should Create a Subcategory for EGUs that Elect to Permanently Retire by December 31, 2032 Similar to the Subcategories EPA Has Proposed in Other Rulemakings.

In two recently proposed rulemakings affecting coal-fired EGUs, EPA has used its authority to create subcategories of affected facilities that elect to retire by a date certain and imposed different standards on subcategories of sources that, essentially, would continue the statu-quo for these units until retirement. These EPA actions recognize that it would make no sense to require an EGU slated to retire in the near term to expend substantial resources on controls in the interim. Specifically, in the proposed Greenhouse Gas Standards and Guidelines for Fossil Fuel-Power Plants, EPA has proposed essentially to retain the current standard (i.e., to not revise the standard) applicable to EGUs that would elect to shutdown by January 1, 2032.[137] EPA has taken a similar approach, tied to a retirement date of December 31, 2032, in the proposed Effluent Limitation Guidelines rule.[138] An EGU that would elect to permanently retire under either of these rules, if finalized, is very unlikely to find it viable to construct significant control upgrades for a revised standard that would become effective in mid-2027, a mere five years before the unit's permanent retirement.

For this reason, if EPA decides to proceed with revised standards in this rulemaking, it should create a subcategory for coal-fired EGUs that elect by the compliance date for the revised standards (i.e., mid-2027) to retire the units by December 31, 2032 (or, January 1, 2032, if EPA prefers to tie this rule to the proposed emission guidelines instead of the effluent limitation guidelines) and maintain the current MATS standards for this subcategory.

X. EPA SHOULD CORRECT THE ERRORS IN ITS IPM MODELING RUNS AND EVALUATE THE IMPACT OF ITS RULES ON THE RELIABILITY OF THE U.S. ELECTRIC POWER GRID.

As the Industry Study explains, EPA's IPM modeling runs contain multiple errors.[139] These errors propagate through the analysis of the costs of the Proposed Rule and skew the amount of generation that likely would have to shut down prematurely as a result of the rule if finalized as proposed. EPA should correct these errors.

EPA should also carefully and seriously evaluate this Proposed Rule, *as well as* the several rules affecting the same EGUs that EPA has recently either finalized or proposed – at a minimum, these include the Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards, the proposed Greenhouse Gas Standards and Guidelines for Fossil Fuel-Power Plants, and the proposed Effluent Limitation Guidelines rulemaking – on the reliability of the Nation's electric power grid. PGen understands that the power industry is undergoing – indeed, it must undergo – a transition to increasing amounts of renewables. Our members include leaders in the fundamental transition to cleaner energy that is currently occurring in the industry. But this

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[137] 88 Fed. Reg. at 33,245.

[138] Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 88 Fed. Reg. 18,824, 18,837 (Mar. 29, 2023).

[139] *See* Industry Study, at 39-44.

transition must proceed in a way that is mindful of affordability as well as, most importantly, reliability. The multitude of recently finalized and proposed regulations that seek to impose substantial costs on fossil-fired generation will inevitably lead to premature retirements, putting the reliability of the power grid at risk. EPA has failed to evaluate the reliability issues that its recent final and proposed rules are creating, individually as well as collectively. The impact of these rules, including this Proposed Rule, on reliability is an important aspect of the problem. EPA should give it the consideration it deserves.

Dated: June 23, 2023

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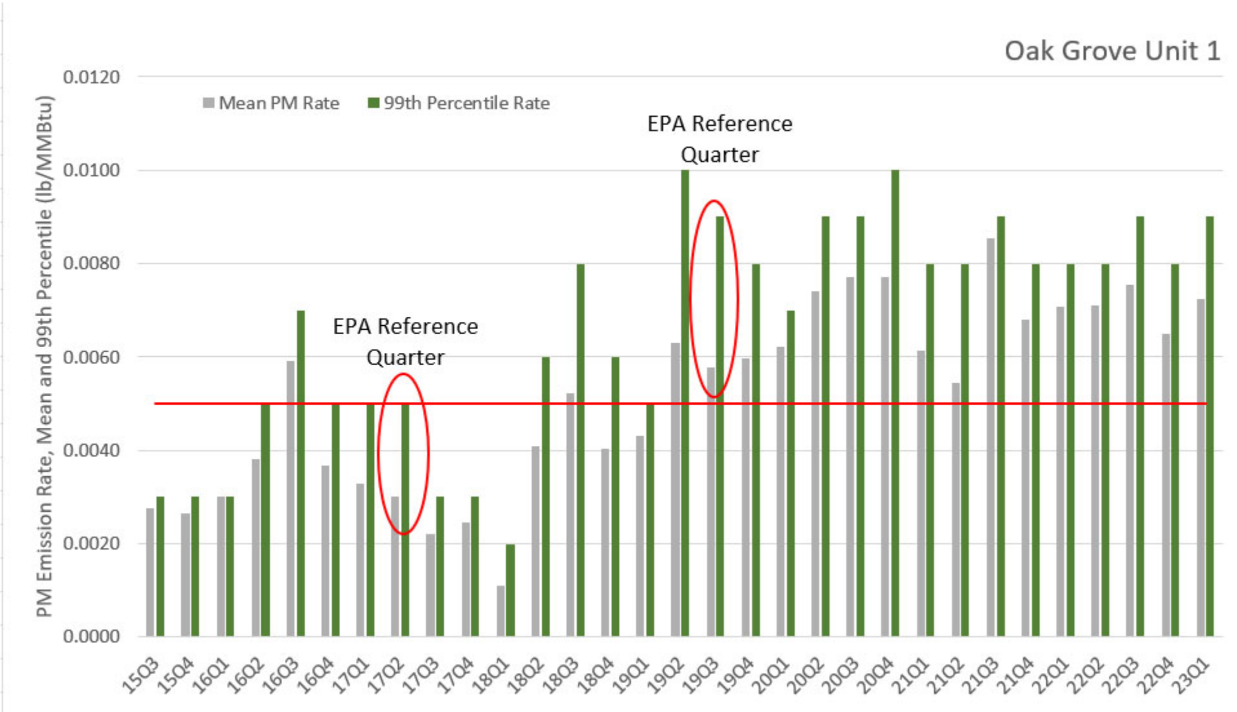
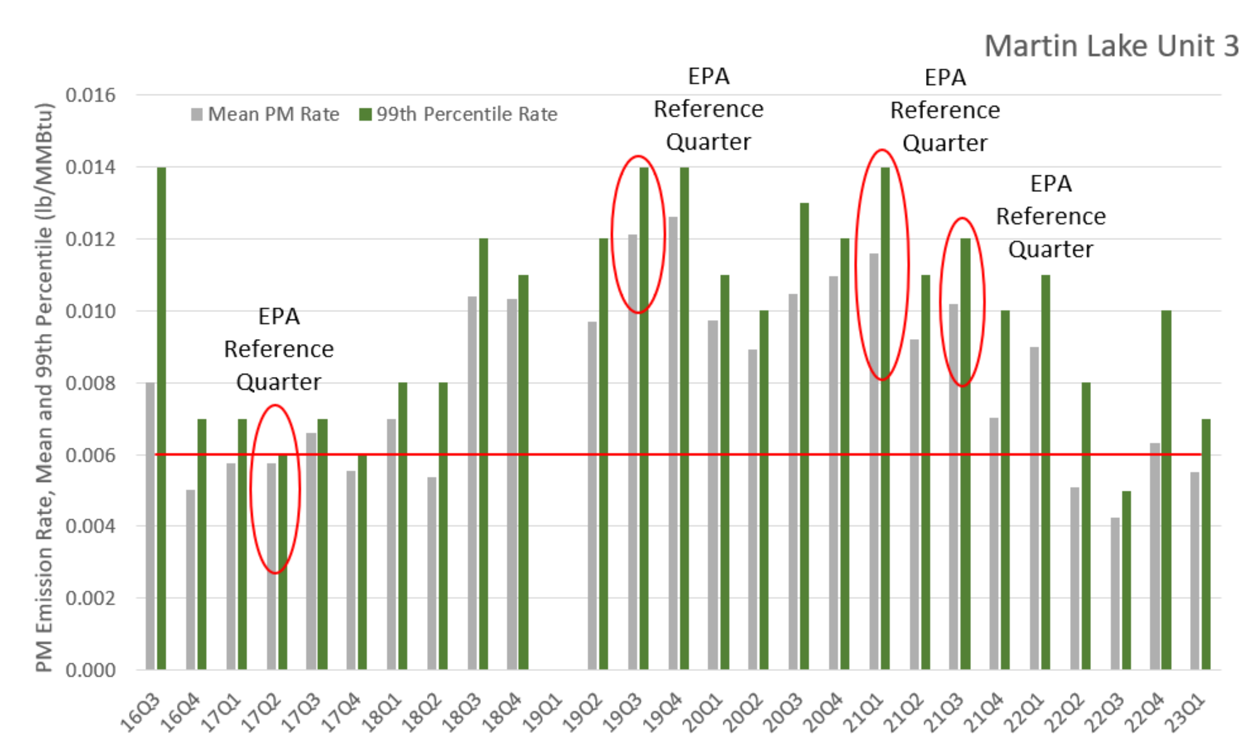
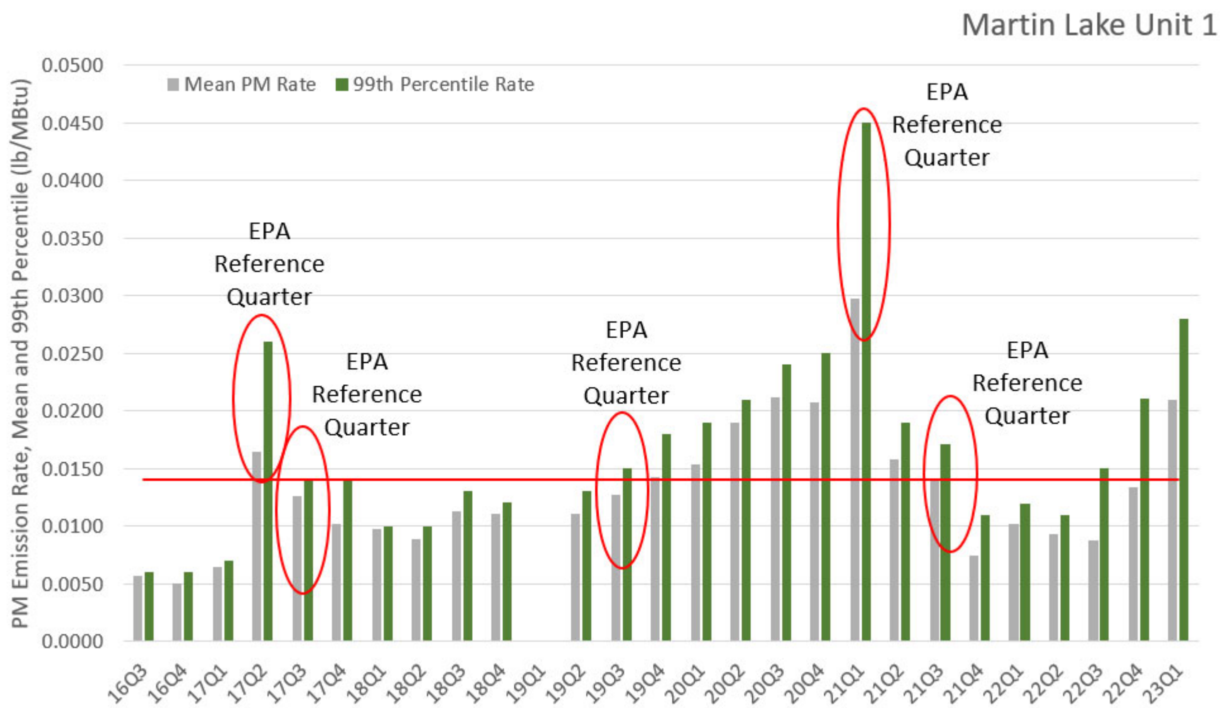
APPENDIX



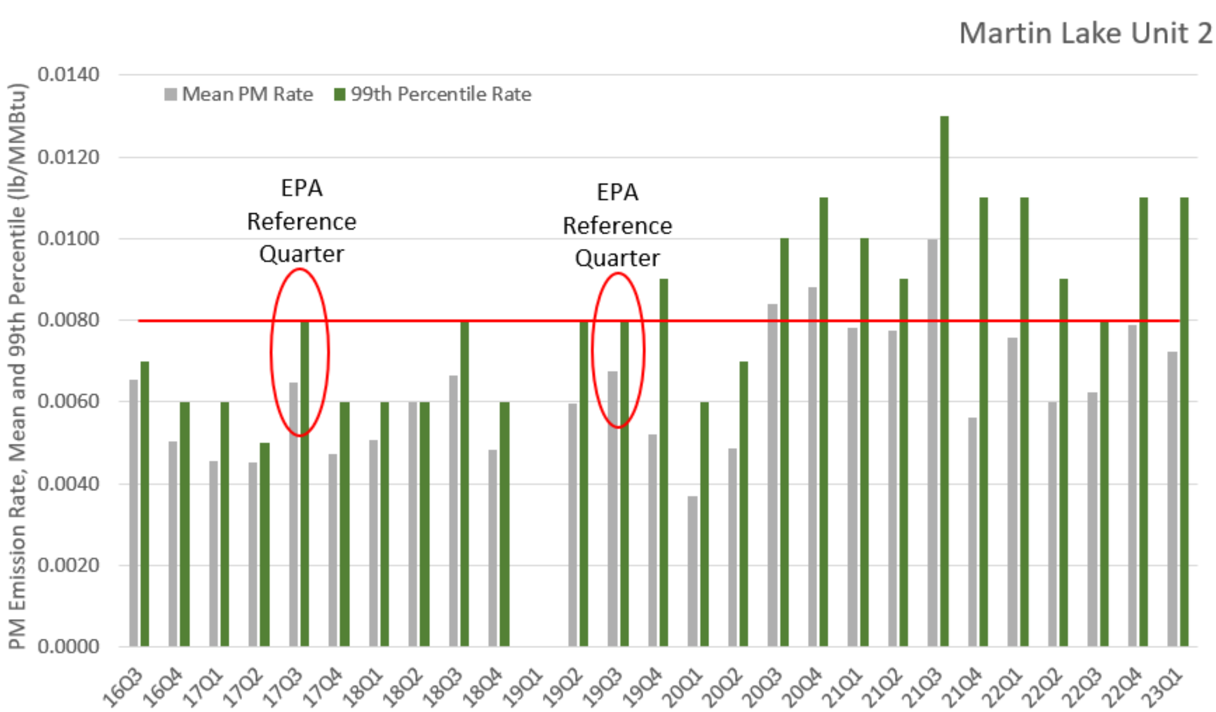
Oak Grove Unit 1 PM Data - 31 Operating Quarters



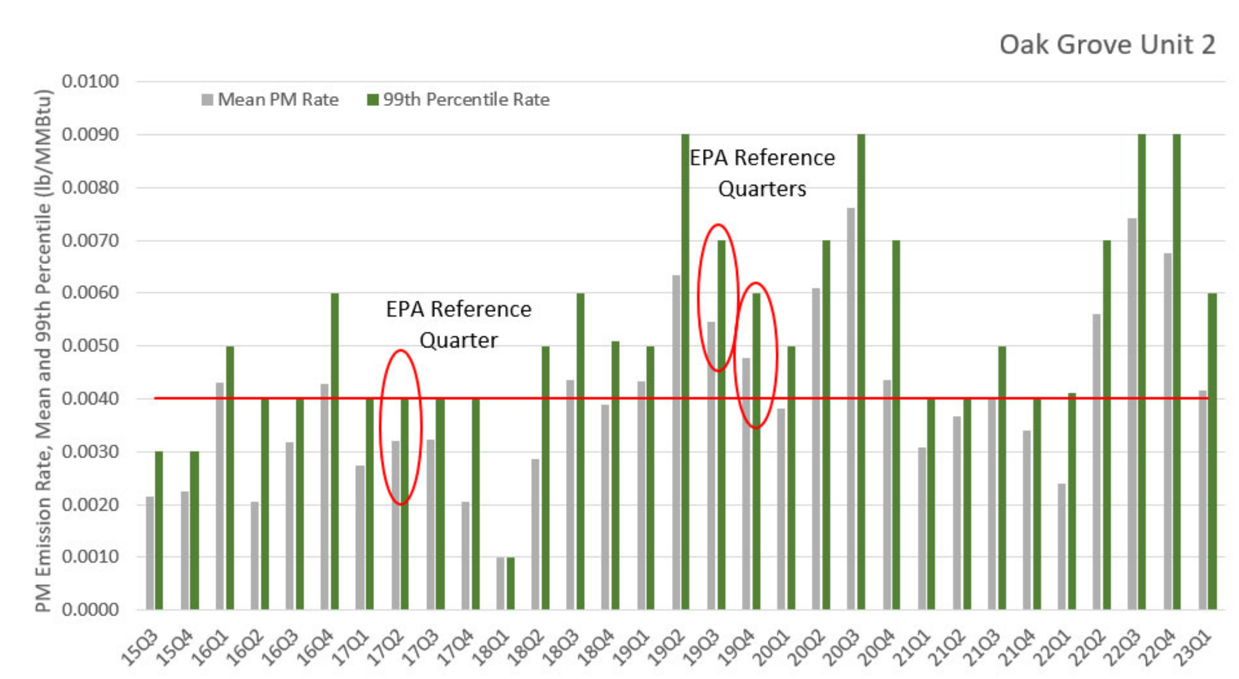
Martin Lake Unit 3 PM Data - 26 Operating Quarters



Martin Lake Unit 1 PM Data - 26 Operating Quarters



Martin Lake Unit 1 PM Data - 26 Operating Quarters



Oak Grove Unit 2 PM Data - 31 Operating Quarters

ATTACHMENT 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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Midwest Ozone Group
NAACO
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Power Generators Air Coalition

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.

[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.

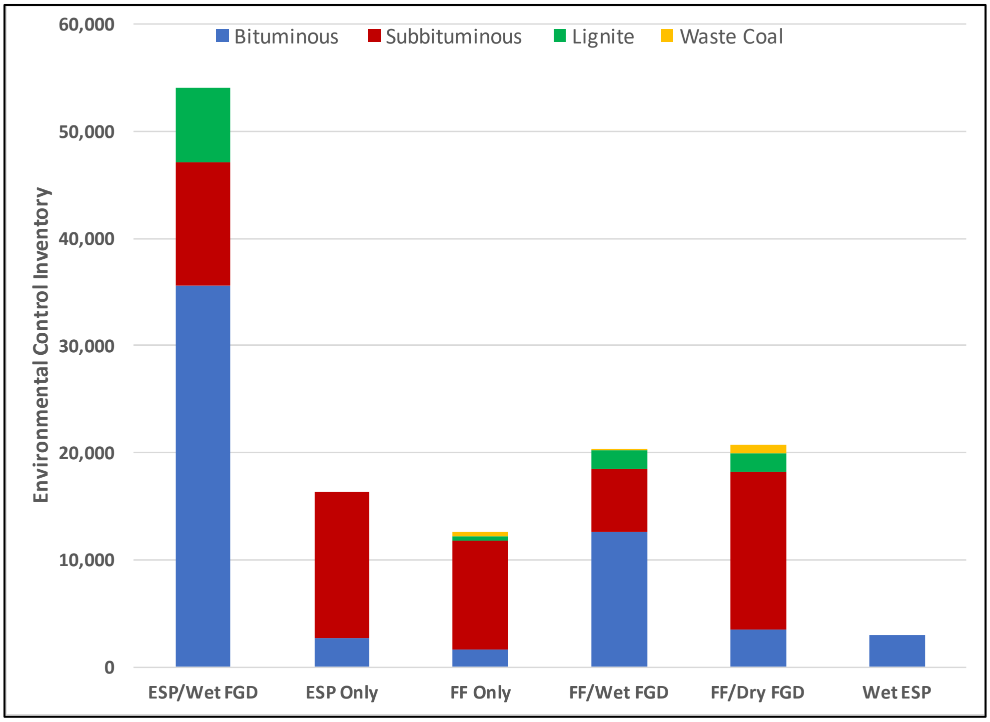

Figure 3-1. Inventory of EPA-Project 2028 Fleet by Control Technology Suite

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.

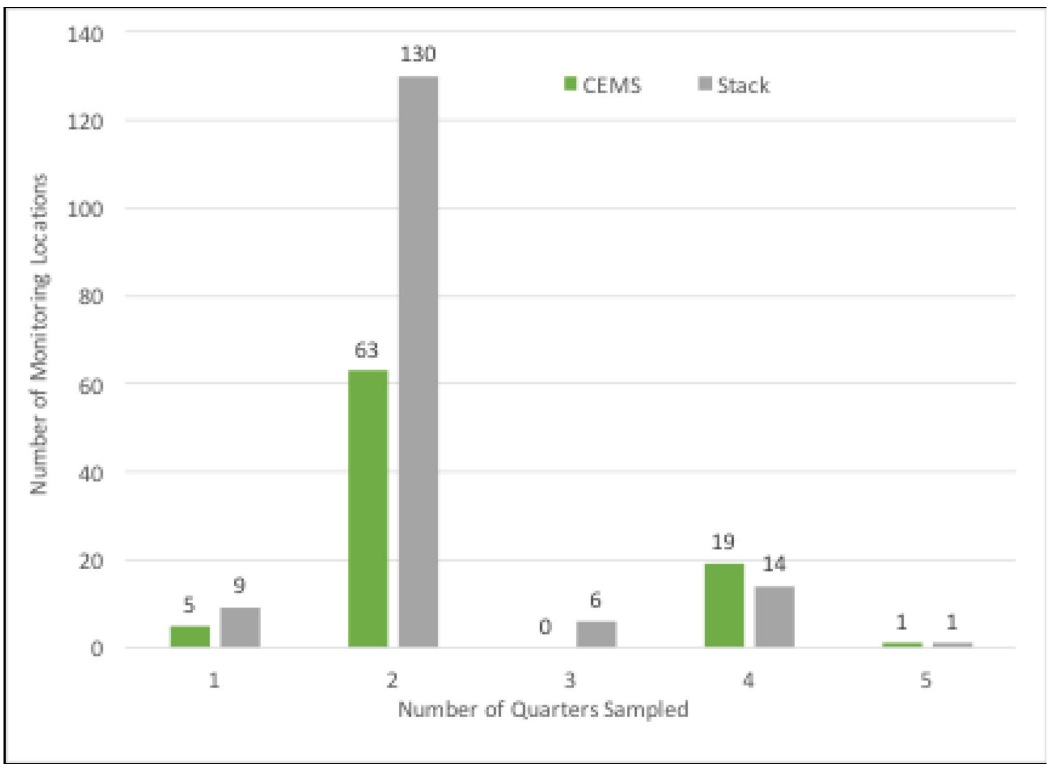

Figure 3-2. Numbers of Quarters Sampled by EPA for Use in PM Database

[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:

Step 1: Quarter Selection. 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]

Step 2. Select Single Quarter. 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.

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

Step 4. Determine PM of 99th Percentile. 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.

[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' 90th percentile fPM rates exceed the 0.0086 lbs/MBtu rate EPA selected for 16 quarters. Ten out of 20 quarters showed 90th percentile fPM rates exceeded the proposed standard of 0.010 lb/MBtu.

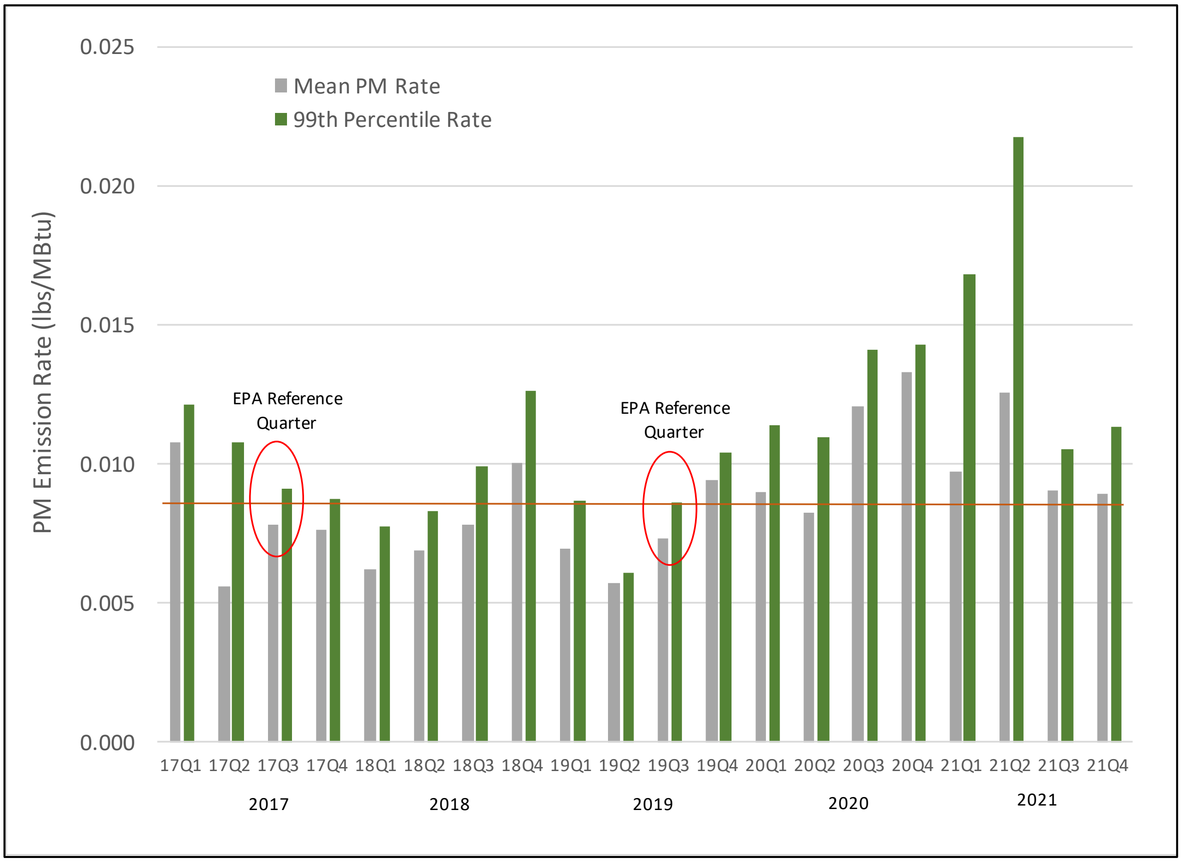

Figure 3-3. Coronado Generating Station: 20 Operating Quarters

Coronado Units 1/2 show how selecting the least PM rate of any quarter, and adopting the 99th 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 99th 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.

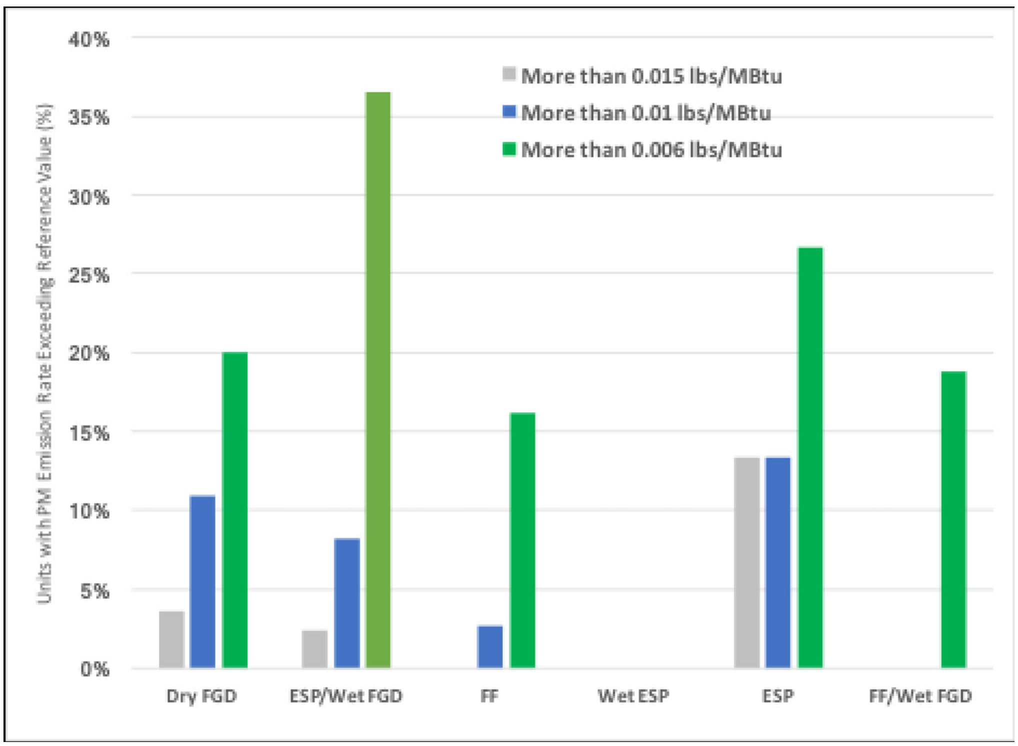

Figure 4-1. Fraction of Units Exceeding Three PM Rates: By Control Technology

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

[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

<u>Proposed Limit: 0.010 lbs/MBtu</u>. 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.

<u>Potential Limit: 0.006 lbs/MBtu</u>. 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 "6/10th" 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

[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.

[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.

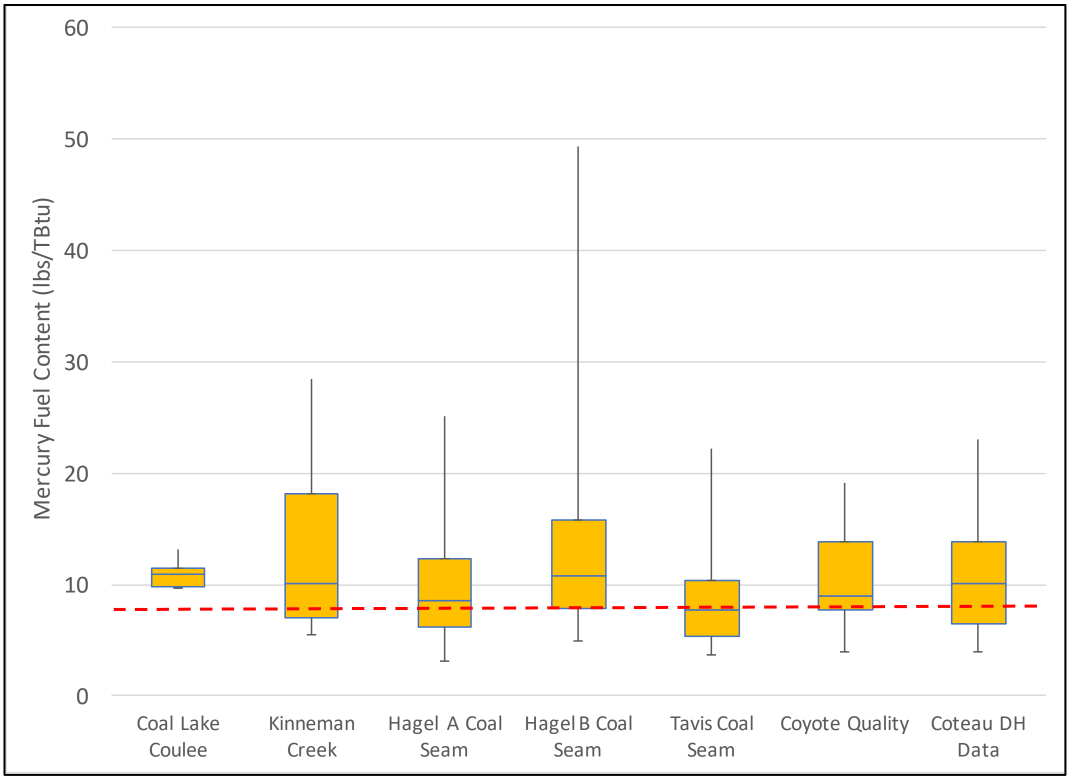

Figure 6-1. Mercury Content Variability for Eight North Dakota Lignite Mines

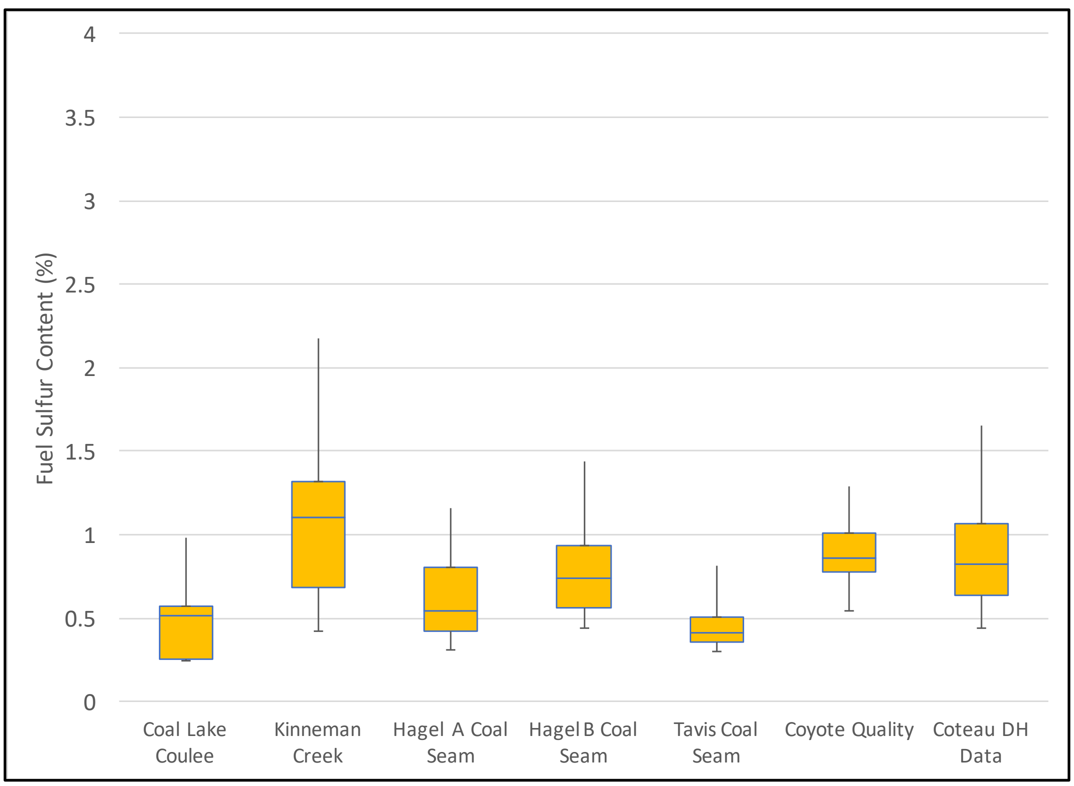

Figure 6-2. Fuel Sulfur Content Variability for Eight North Dakota Lignite Mines

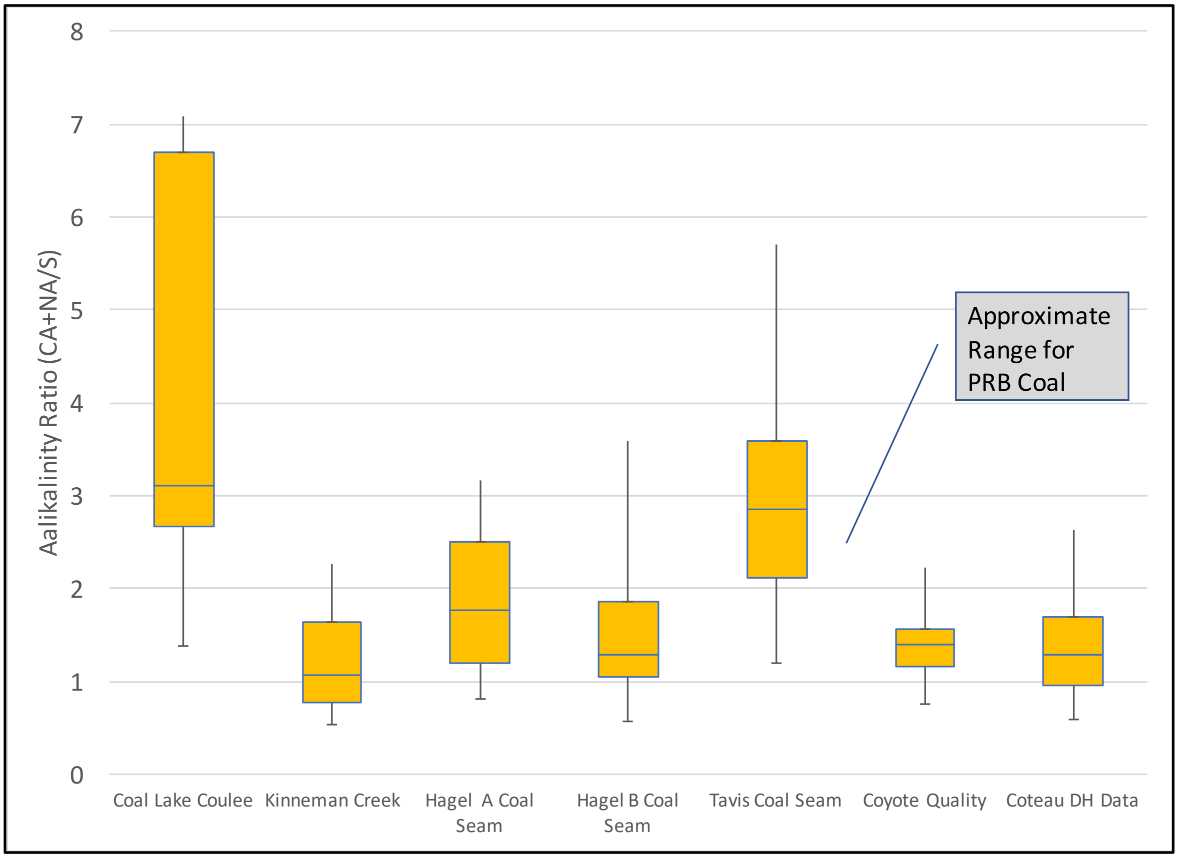

Figure 6-3. Fuel Alkalinity/Sulfur Ratio for Eight North Dakota Mines

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 75th 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.

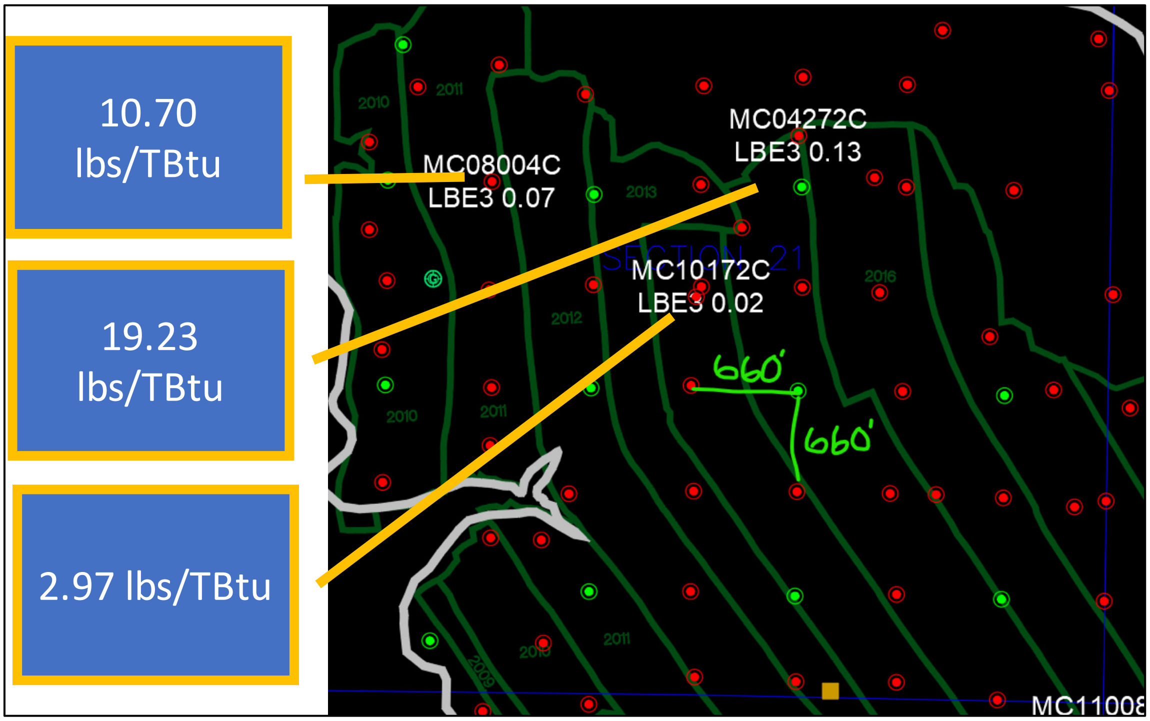

Figure 6-4. Spatial Variation of Hg in a Lignite Mine

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 95th 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.

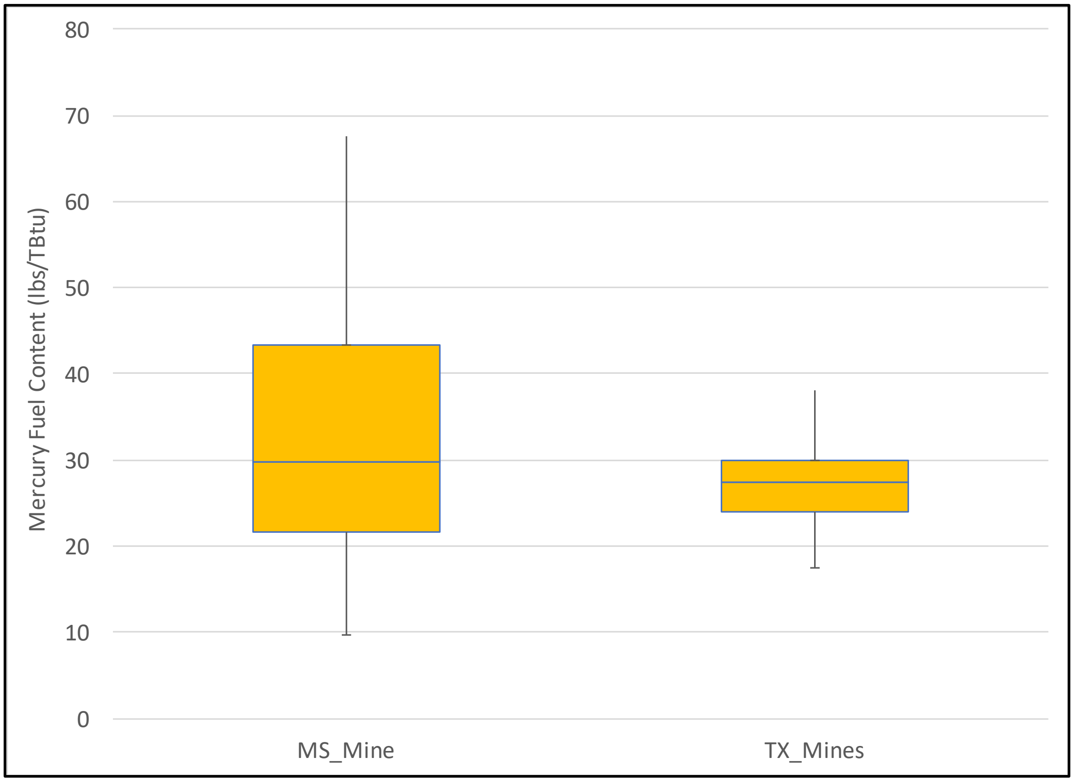

Figure 6-5. Mercury Variability for Two Gulf Coast Sources: Mississippi, Texas

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 95th percentile value of the Texas lignite Hg values from Figure 6-5, the required Hg removal would be 96-97%.

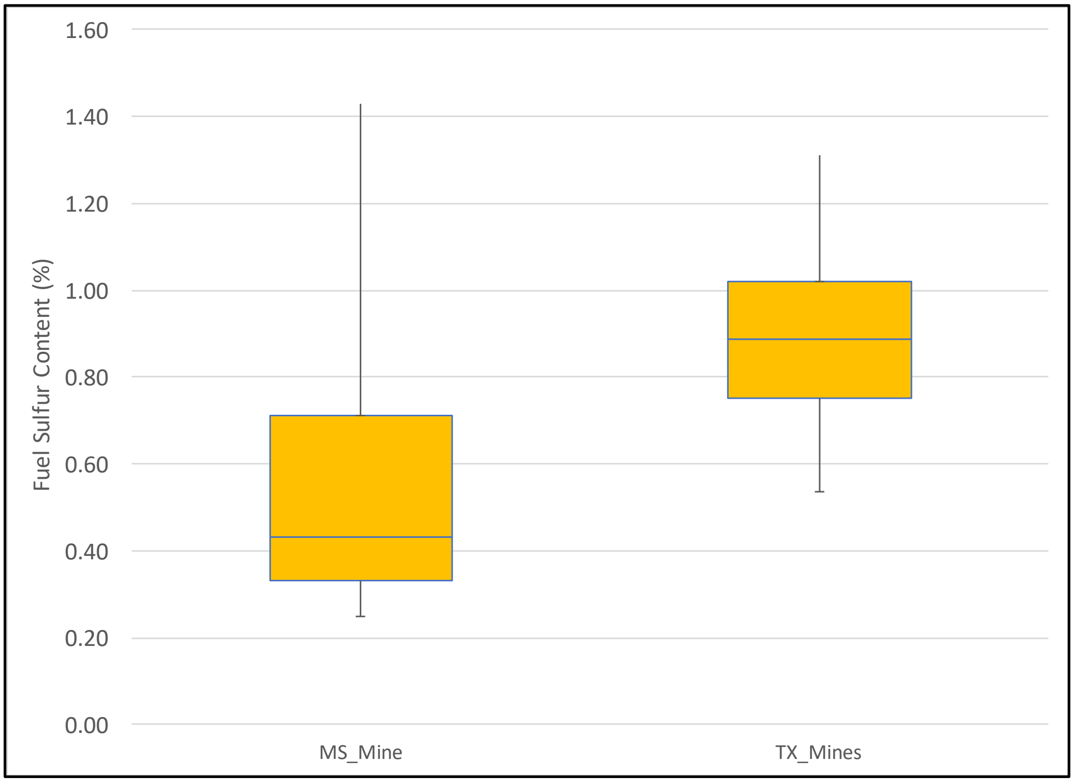

Figure 6-6. Sulfur Variability for Mississippi, Texas Lignite Mines

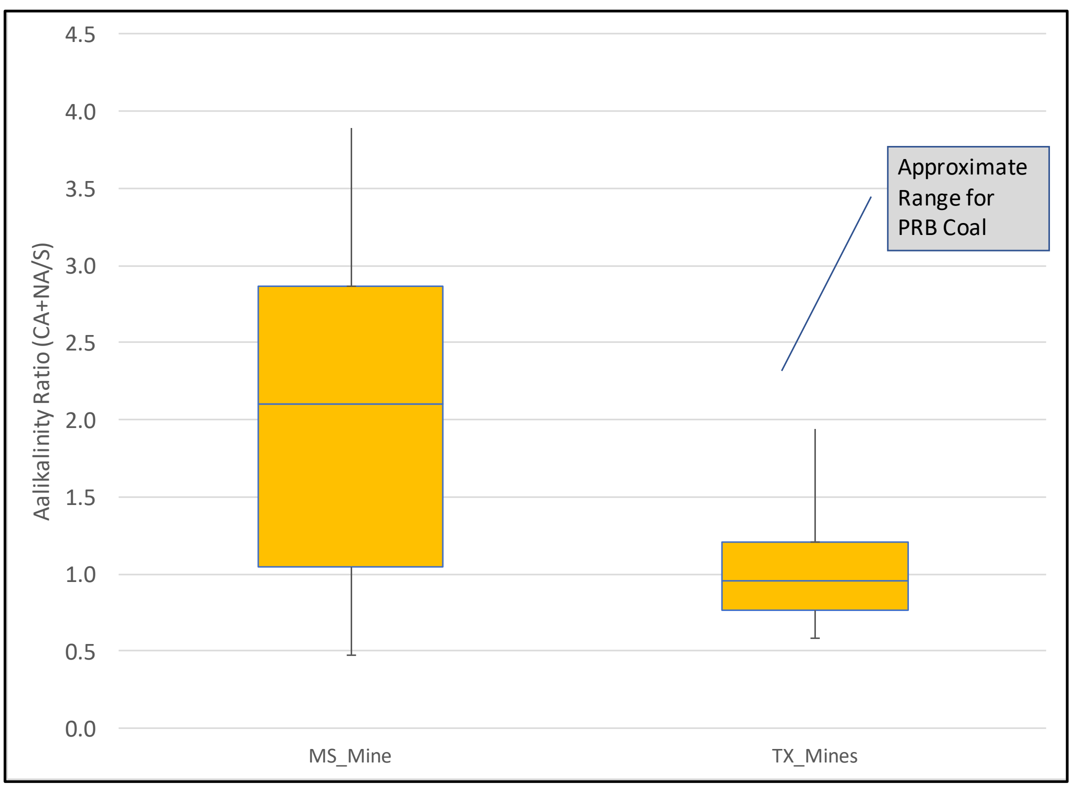

Figure 6-7. Fuel Alkalinity/Sulfur Ratio for Mississippi, Texas Lignite Mines

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.

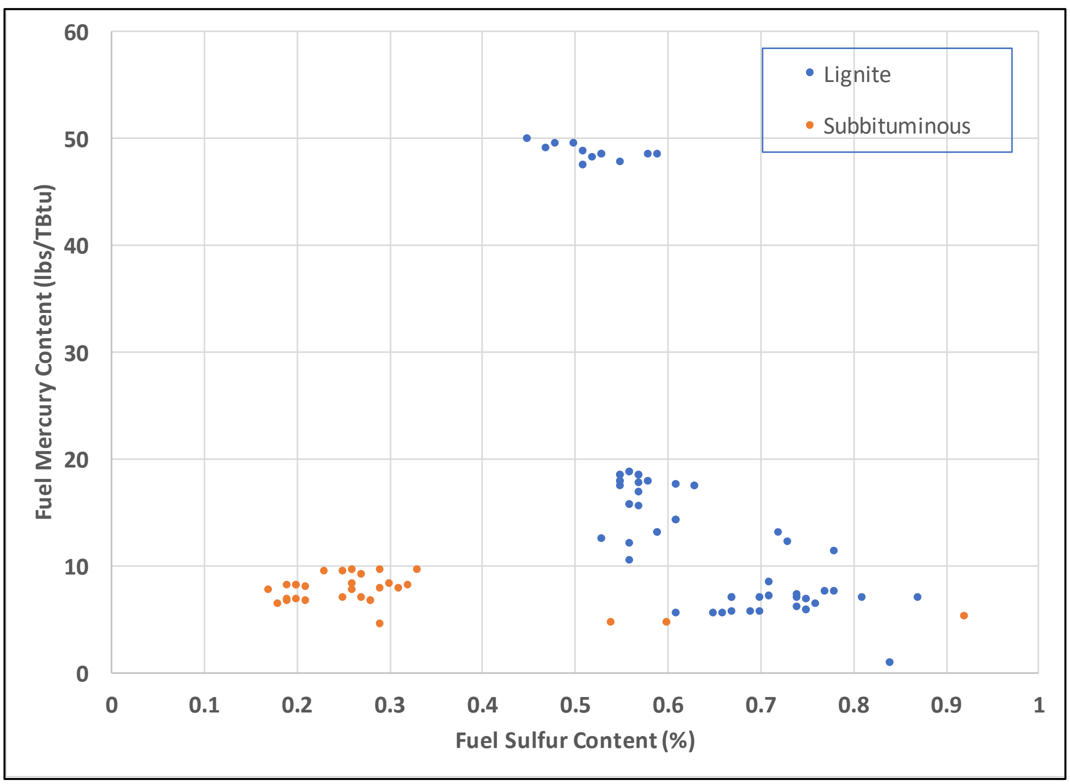

Figure 6-8. Lignite Hg and Sulfur Content Variability: 2021 EIA Submission

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

[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.

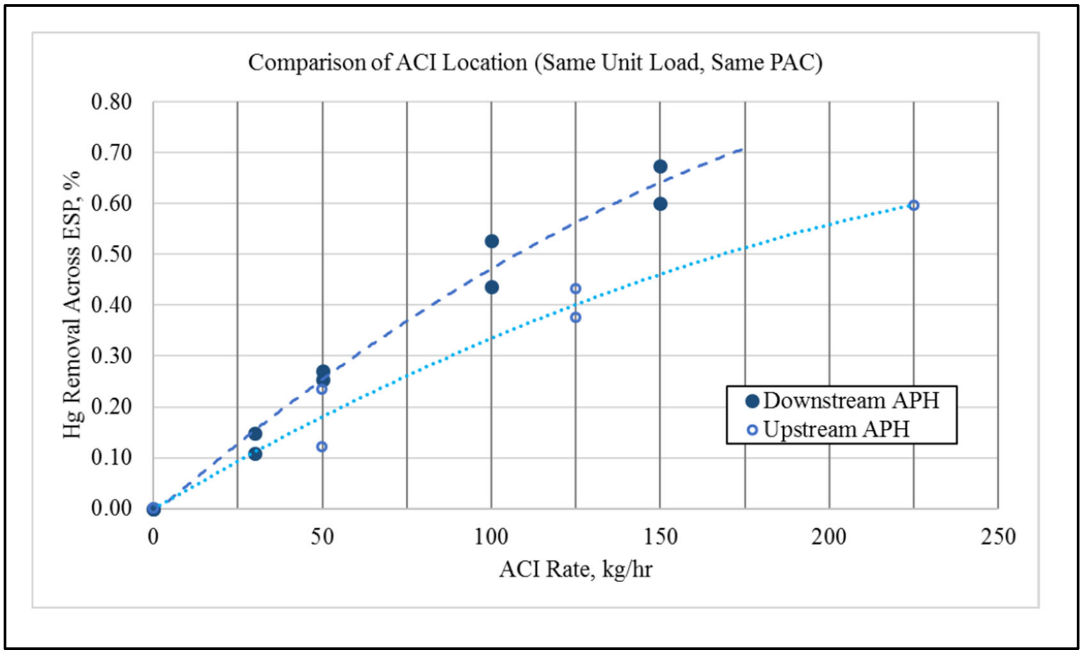

Figure 6-9. Sorbent Hg Removal in ESP in Lignite-Fired Unit: Effect of Injection Location

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.

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[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.

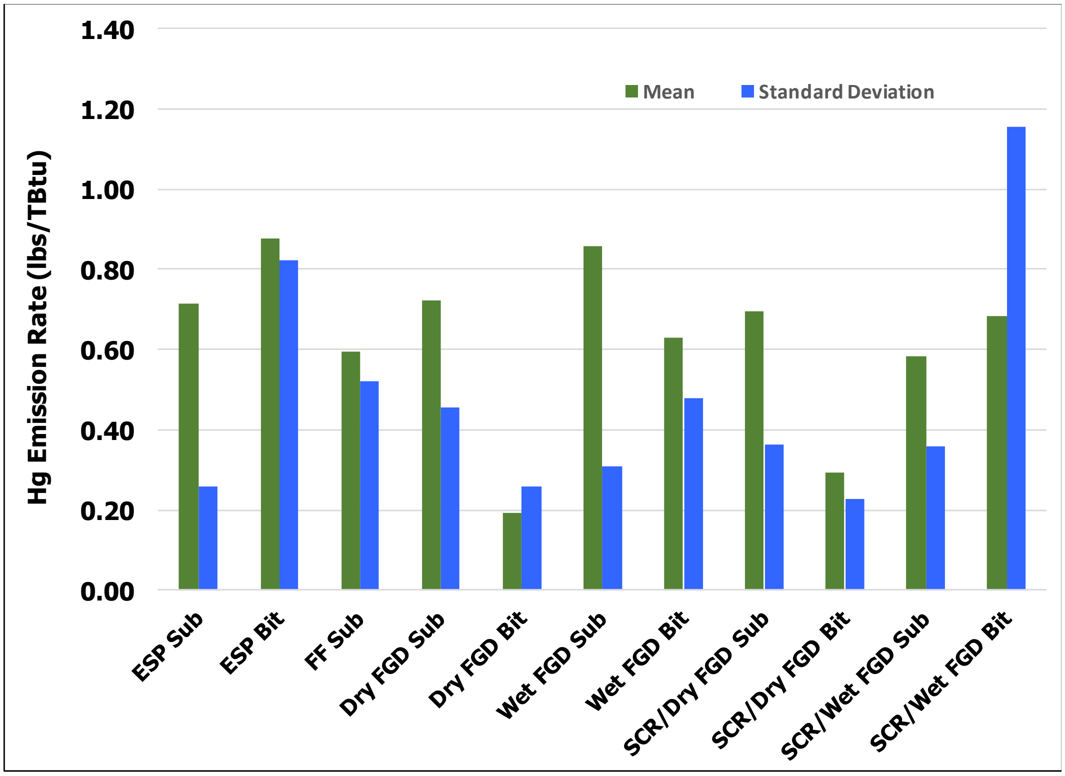

Figure 7-1. Mean, Standard Deviation of Annual Hg Emissions: 2018

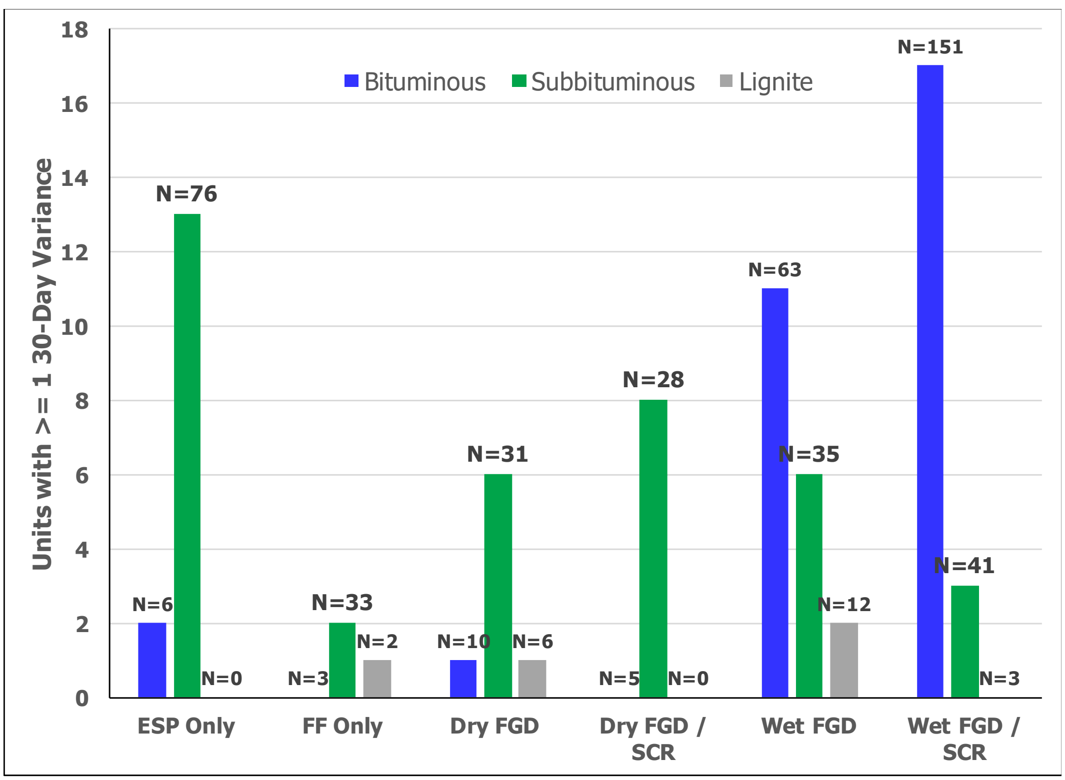

Figure 7-2. Mean, Standard Deviation of Annual Hg Emissions: 2018

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.

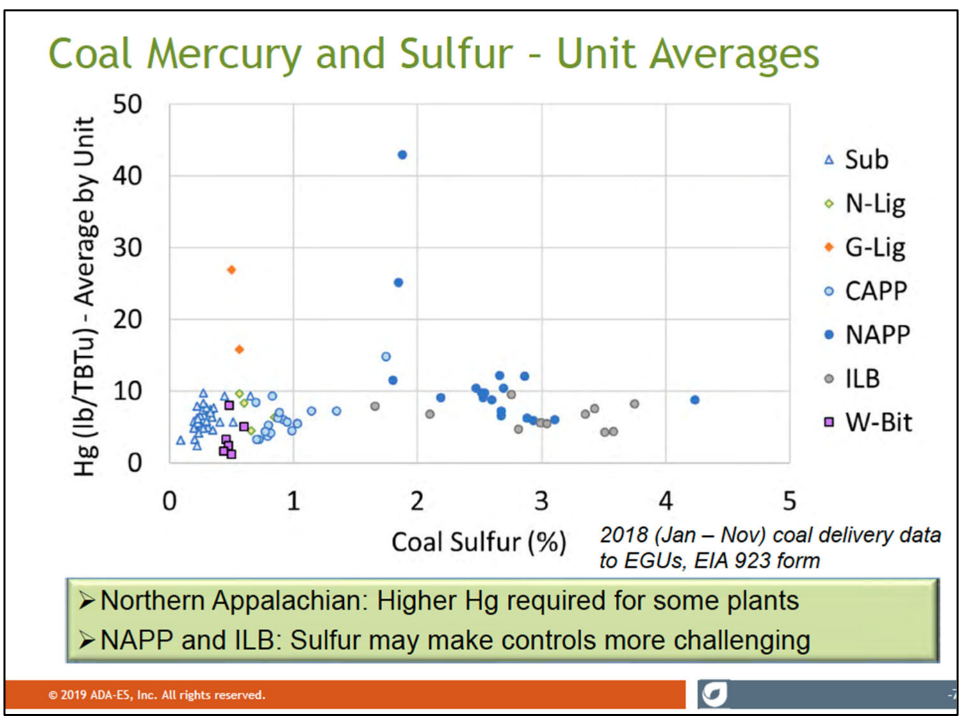

Figure 7-3. Annual Average of Fuel Hg, Sulfur Content in Coal

[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.

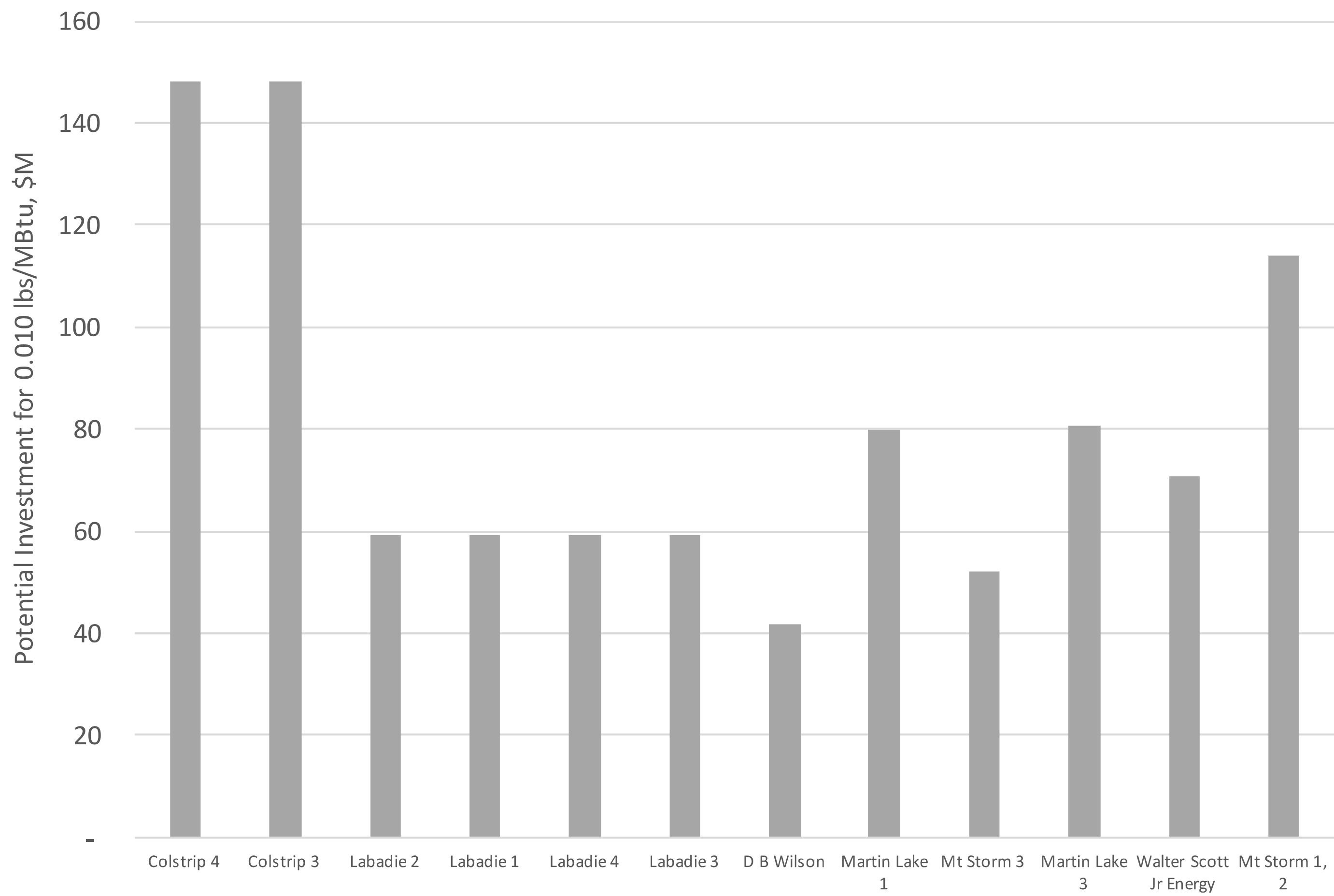
8.2 Summary

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 99th 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.

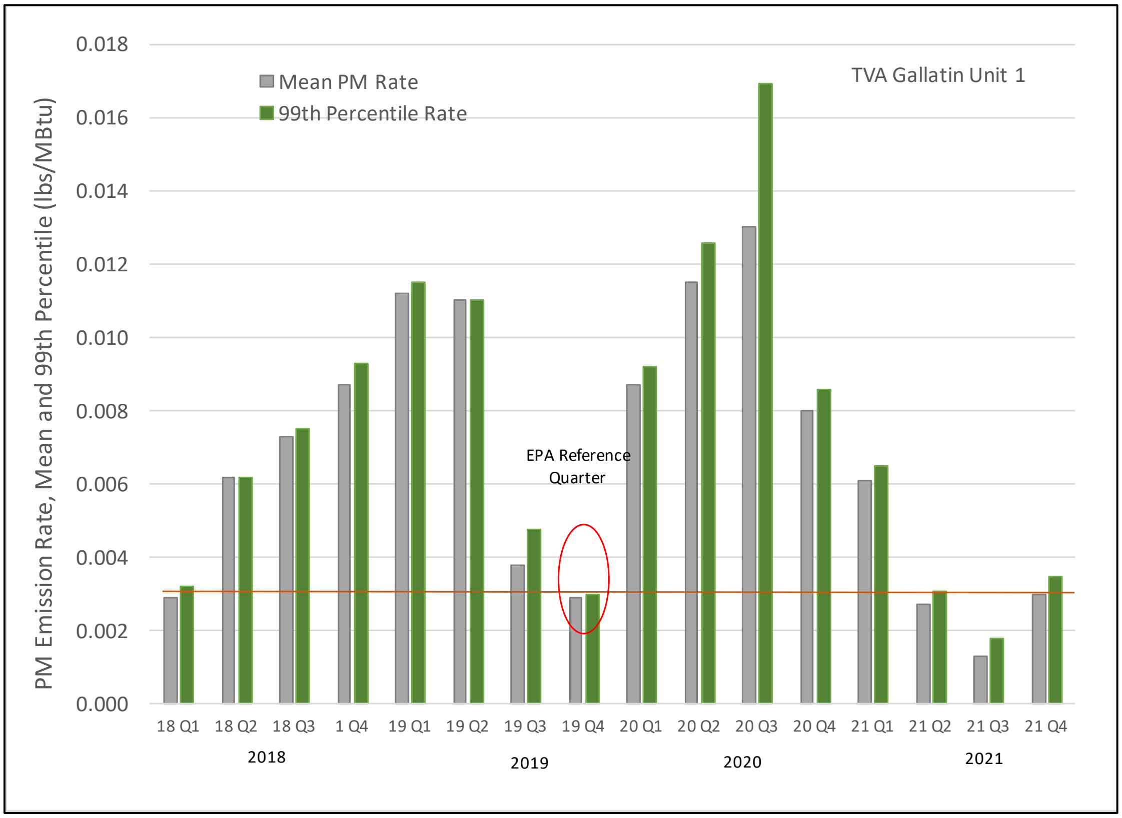
- TVA Gallatin Unit 4. EPA selected 0.0022 lbs/MBtu as the reference PM rate, using Q1 of 2021. Of the 14 quarters reporting data, two quarters report PM rates equal to this rate, while two are below this rate.

- 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.

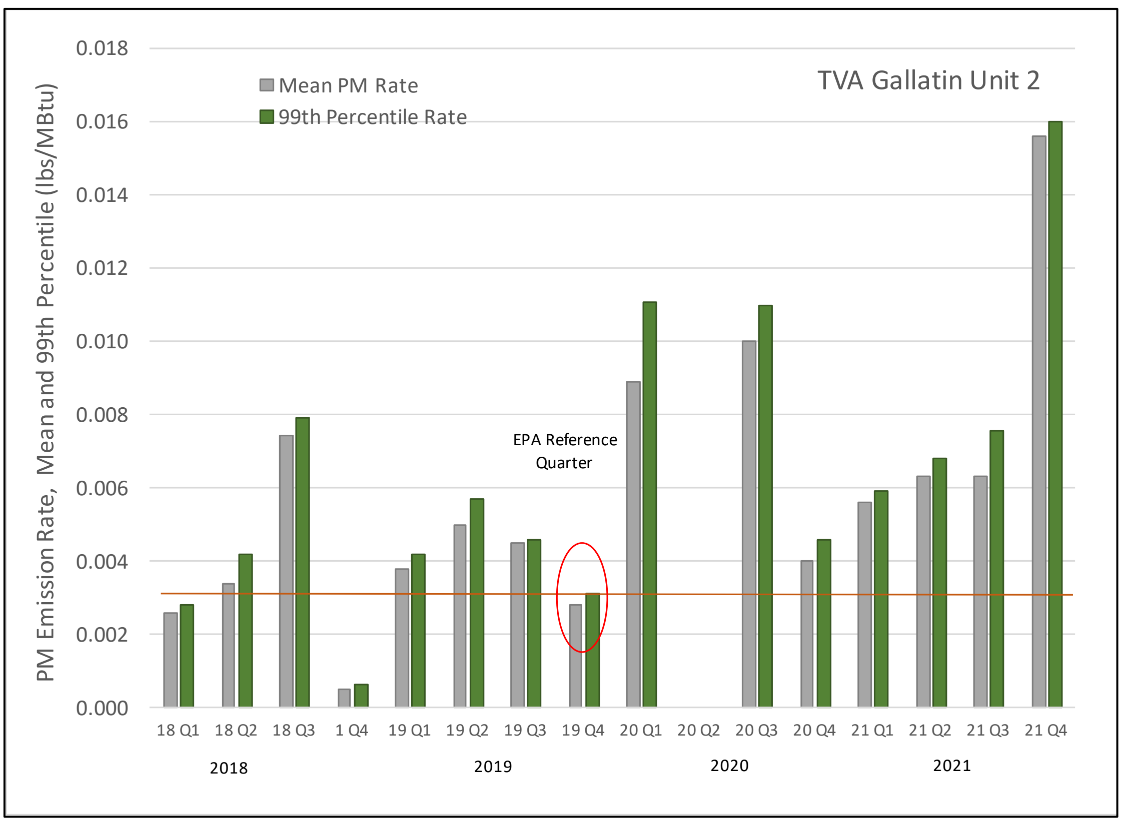
- LG&E/KU Mill Creek Unit 4. EPA selected 0.0035 lbs/MBtu as the reference PM rate, using Q4 of 2021. With the exception of the previous quarter, this value is the lowest of any reported since 2017 by a significant margin.

- 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.

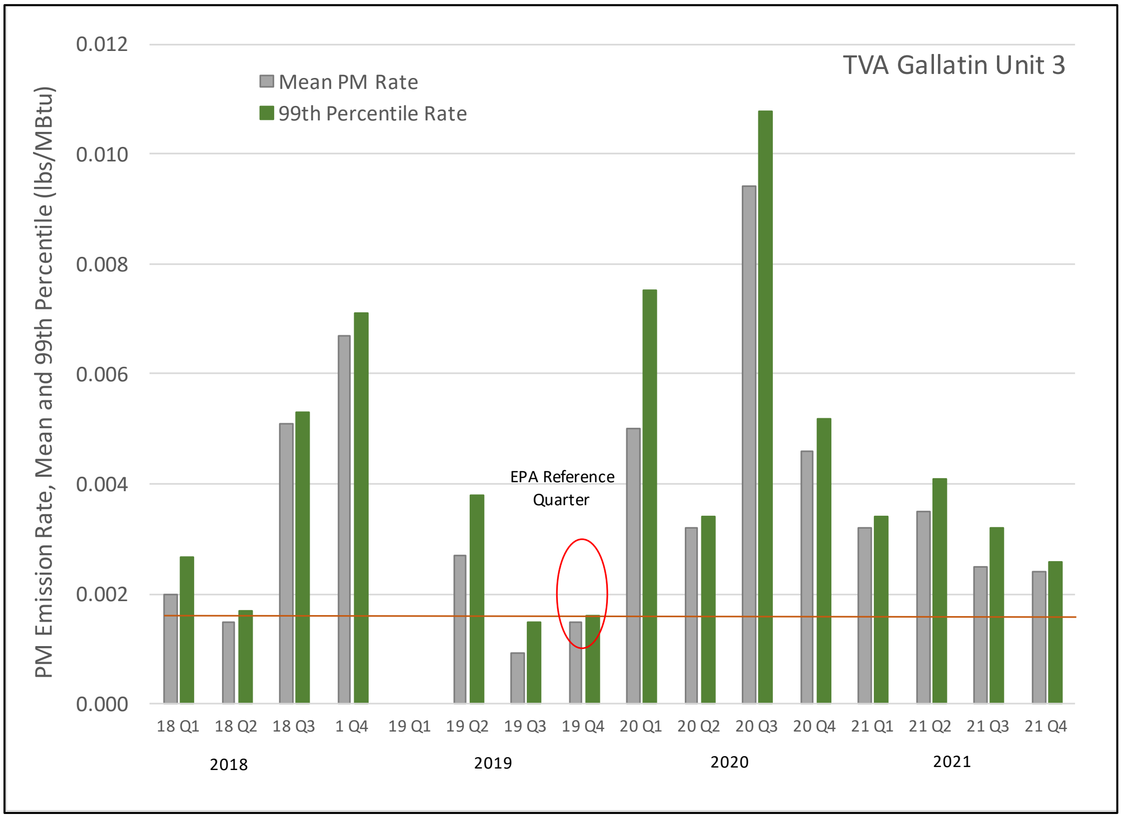
- Alabama Power Miller Unit 1. EPA selected 0.004 lbs/MBtu as the reference PM rate, using Q3 of 2017. Data for this unit is displayed from Q1 2017 through Q4 2022. The designated rate represents a significant reduction from approximately half of the reporting quarters since Q1 2020.

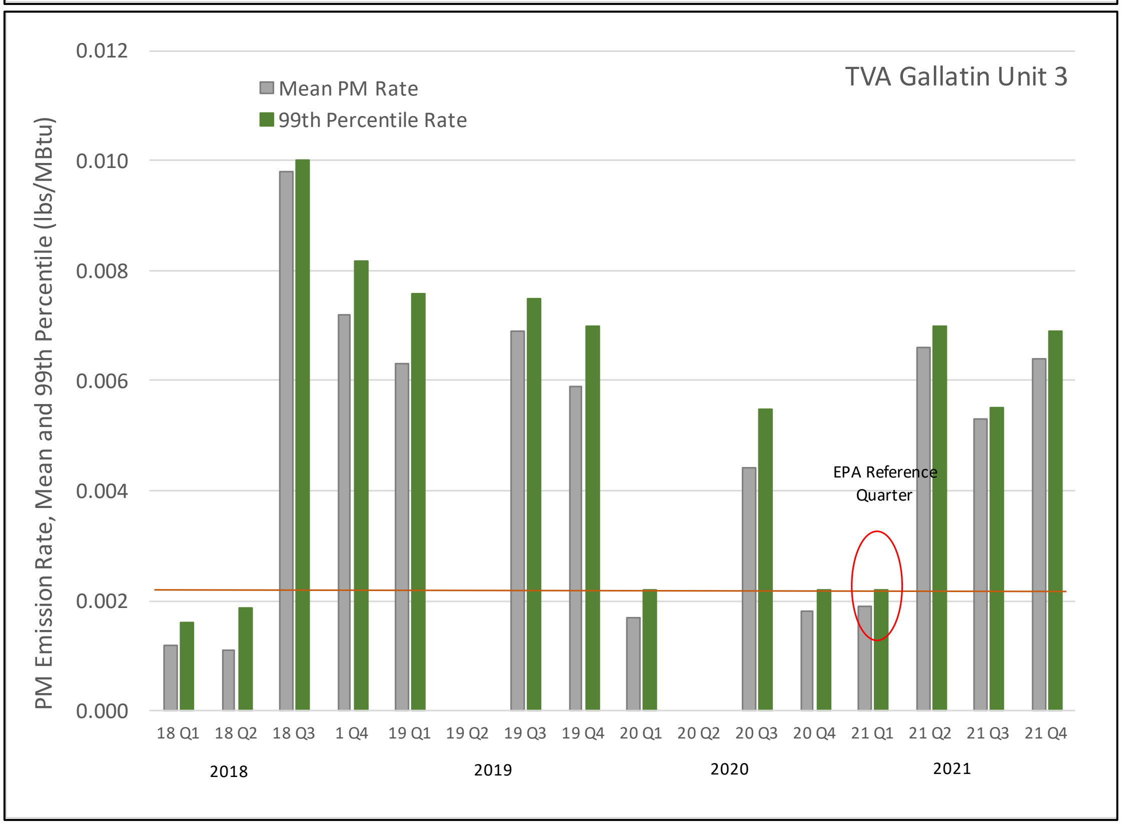


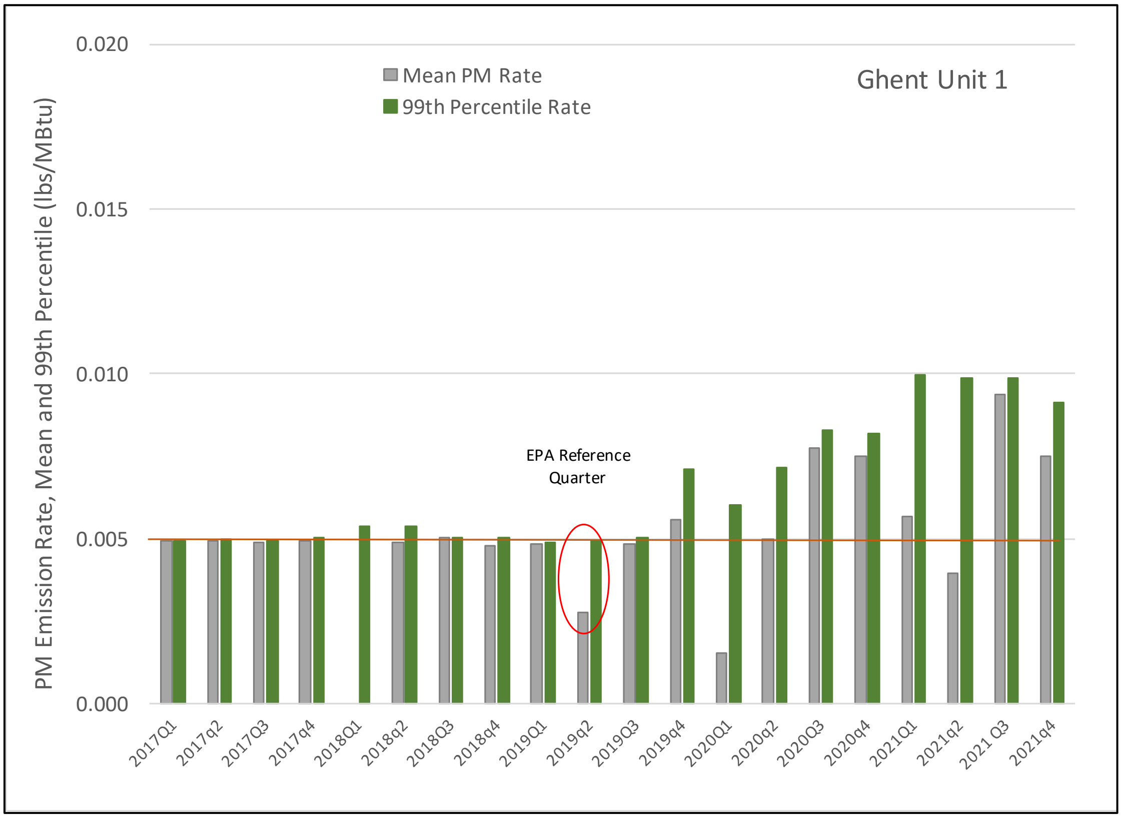
TVA Gallatin Unit 1
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.018
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
EPA Reference Quarter
18 Q1
18 Q2
18 Q3
1 Q4
19 Q1
19 Q2
19 Q3
19 Q4
20 Q1
20 Q2
20 Q3
20 Q4
21 Q1
21 Q2
21 Q3
21 Q4
2018
2019
2020
2021

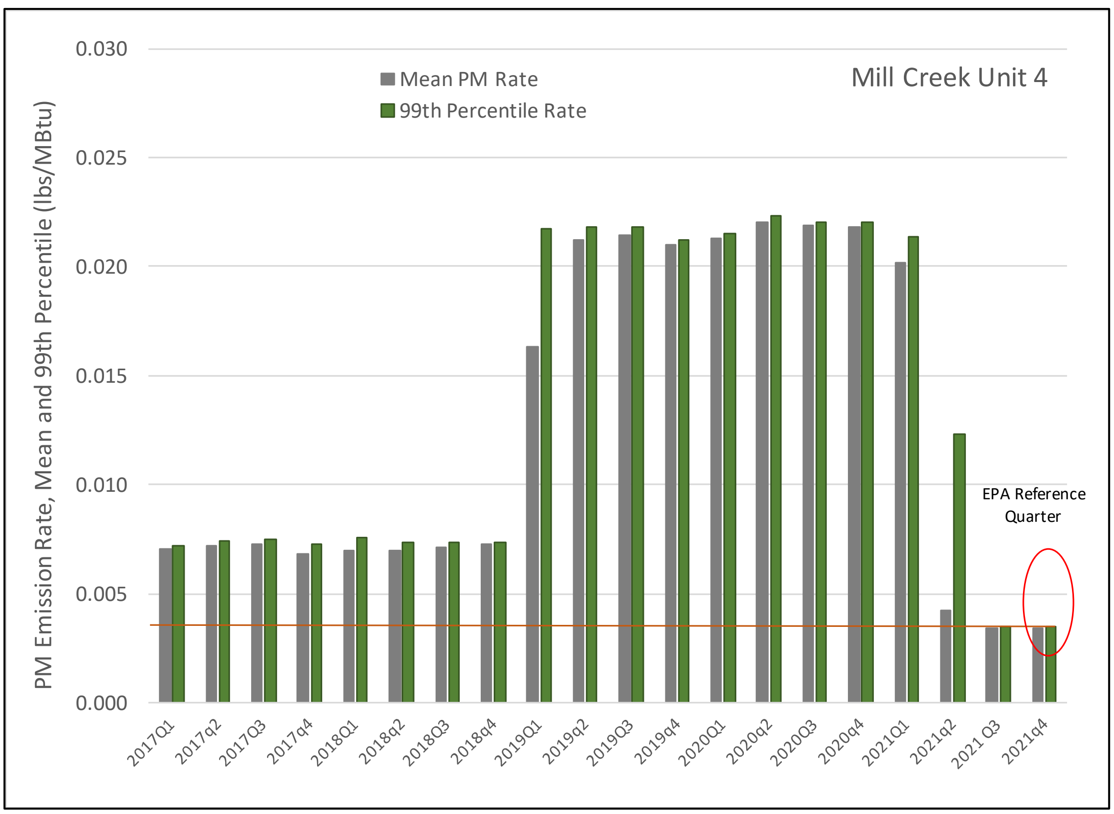


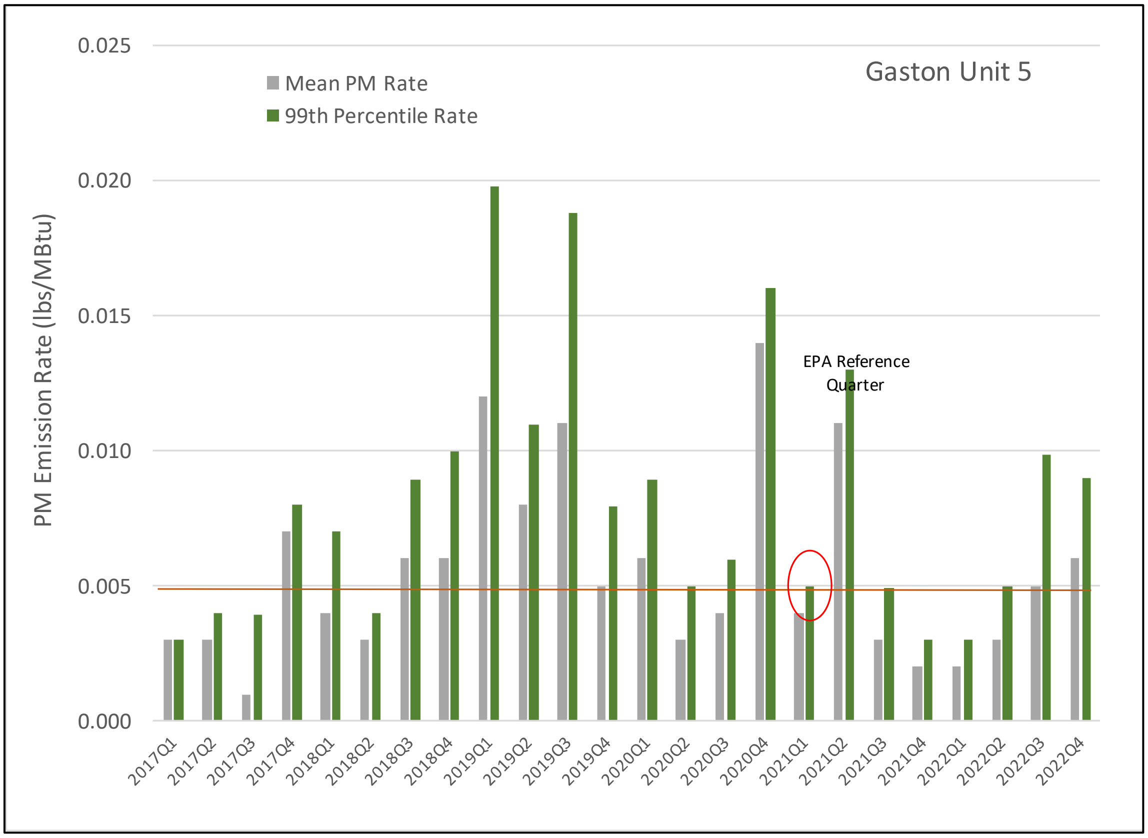
TVA Gallatin Unit 2
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.018
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
EPA Reference Quarter
18 Q1
18 Q2
18 Q3
1 Q4
19 Q1
19 Q2
19 Q3
19 Q4
20 Q1
20 Q2
20 Q3
20 Q4
21 Q1
21 Q2
21 Q3
21 Q4
2018
2019
2020
2021


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

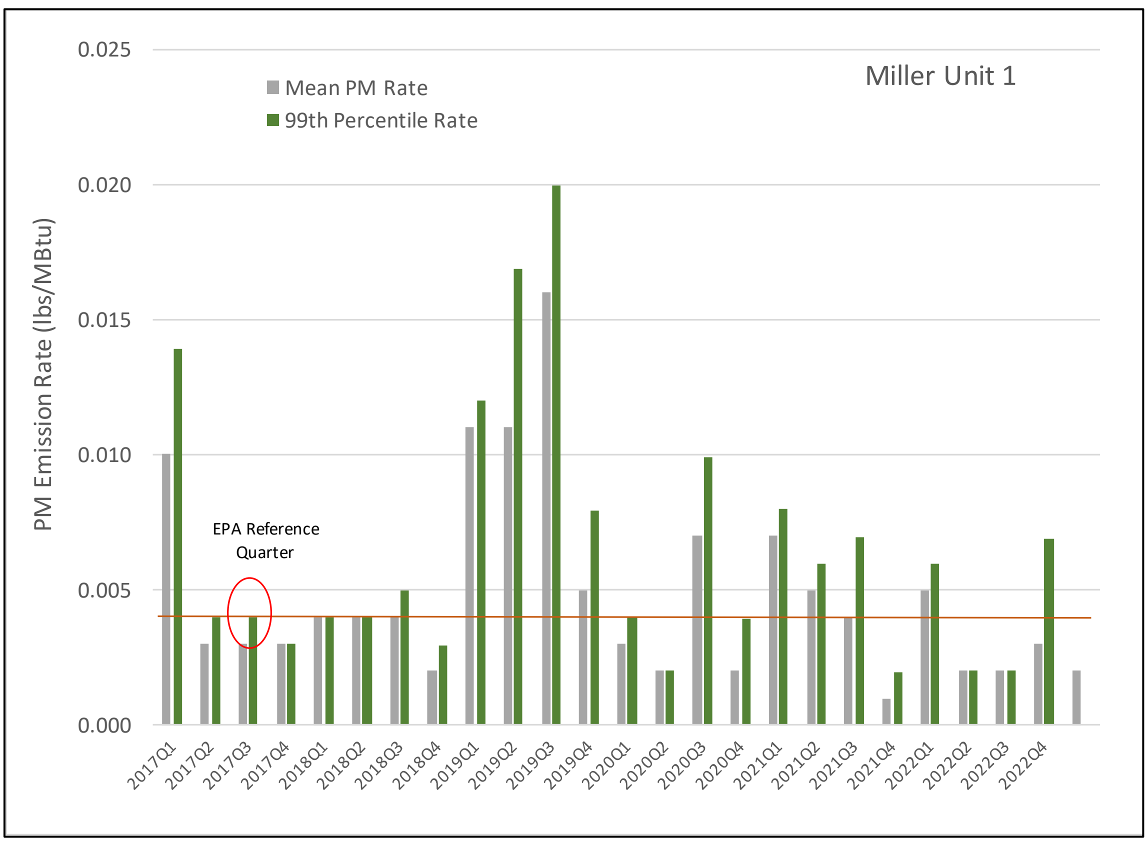

TVA Gallatin Unit 3
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.012
0.010
0.008
0.006
0.004
0.002
0.000
EPA Reference Quarter
18 Q1
18 Q2
18 Q3
1 Q4
19 Q1
19 Q2
19 Q3
19 Q4
20 Q1
20 Q2
20 Q3
20 Q4
21 Q1
21 Q2
21 Q3
21 Q4
2018
2019
2020
2021


Ghent Unit 1
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
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

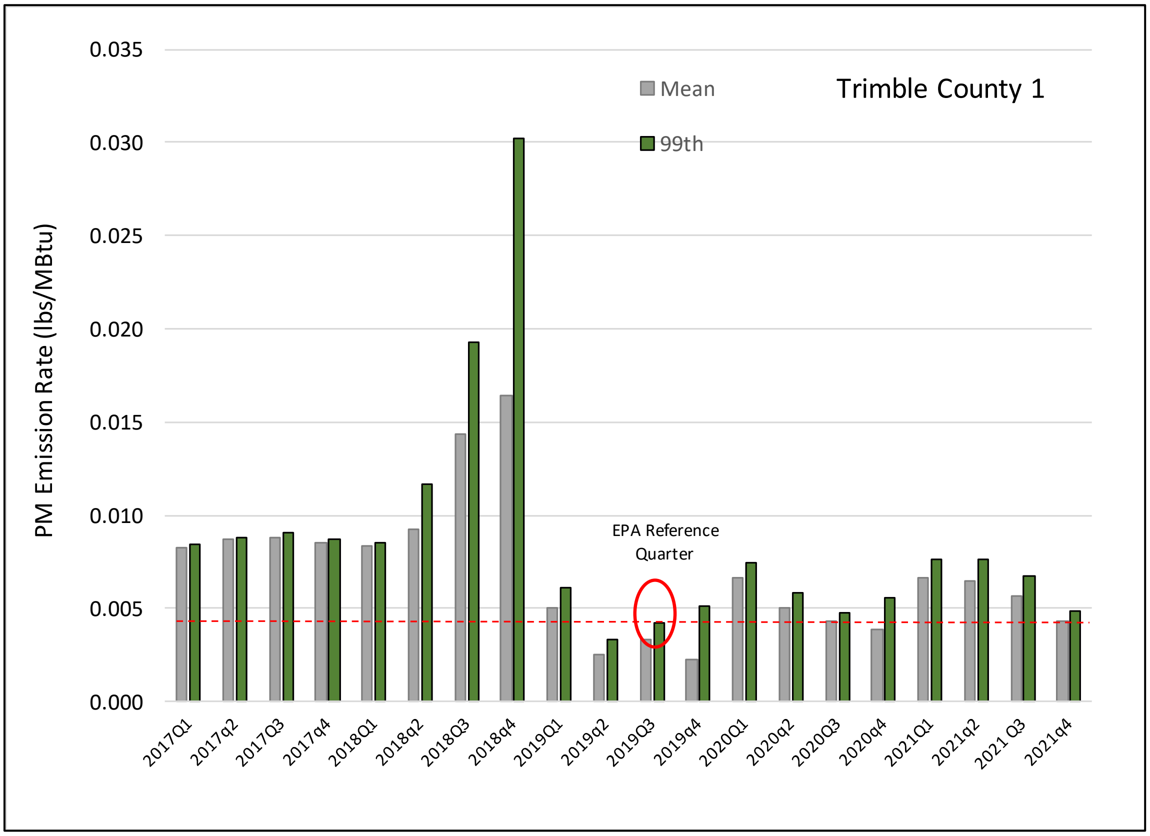

Mill Creek Unit 4
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.030
0.025
0.020
0.015
0.010
0.005
0.000
EPA Reference Quarter
2017Q1
2017q2
2017Q3
2017q4
2018Q1
2018q2
2018Q3
2018q4
2019Q1
2019q2
2019Q3
2019q4
2020Q1
2020q2
2020Q3
2020q4
2021Q1
2021q2
2021 Q3
2021q4



Gaston Unit 5
Mean PM Rate
99th Percentile Rate
PM Emission Rate (lbs/MBtu)
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 2021Q3 2021Q4 2022Q1 2022Q2 2022Q3 2022Q4



Miller Unit 1
Mean PM Rate
99th Percentile Rate
PM Emission Rate (lbs/MBtu)
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 2021Q3 2021Q4 2022Q1 2022Q2 2022Q3 2022Q4



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

ATTACHMENT B

Delivering water and power™

ESP BMP QUARTERLY REVIEW – Q1 2019

Introduction / Executive Summary

The Electrostatic Precipitators (ESPs) at Coronado Generation Station (CGS) are operated and maintained in accordance with the "CGS Best Management Practices and Optimization Plan For Existing Electrostatic Precipitator Equipment" dated January 16, 2009.

Operation and maintenance activities have been mostly routine in nature and there were no permit deviations during this reporting period. During the Fourth Quarter of 2018 Unit 1 had a Major Overhaul that began November 11 and continued on to Quarter 1 ending February 12. This outage was of sufficient duration to work on the ESPs. In addition, Unit 2 had a Turbine Inspection Outage starting February 9 and continuing on to the Second Quarter and was of sufficient duration to perform work on the ESPs. The completed work on the ESPs during the outages is as detailed below:

1.0 Unit 1 – U1 Major Overhaul
(November 20, 2018 – February 12, 2019)

- 1.1 Wire Replacements
- 1.2 Weld Repairs and Electrical Repair Work
- 1.3 Transformer cleaning & maintenance
- 1.4 Vacuum out the precipitators and boiler exit duct
- 1.5 Perform explosive blasting
- 1.6 Repair grounded precipitator fields

2.0 Unit 2 – U2 Turbine Inspection Outage
(February 9 into Second Quarter 2019)

- 2.1 Repair grounded precipitator fields
- 2.2 Vacuum out the precipitators and boiler exit duct
- 2.3 Rap Curtains and remove bridges

ESP OPERATIONAL PROCESS AND PRACTICES

Operational Training

CGS Management requires all personnel responsible for operating ESP equipment to be trained according to a comprehensive curriculum administered by the CGS Training department.

Operator training records are maintained by the CGS training department. Hardcopy records of Best Management Practices (BMPs) training are archived in the environmental offices as they are submitted.

Operating Instructions and Procedures

CGS maintains documented operating procedures. The area supervisors are responsible for ensuring that these procedures are followed consistently by all area personnel authorized to operate ESP equipment.

Area supervisors ensure that operating procedures are accessible, are included in CGS training curriculum and are consistently followed.

Periodic Inspections

The on duty Operations OM Supervisor IV shall assign personnel to complete periodic rounds (daily, weekly, or monthly) to visually inspect ESP equipment for abnormal conditions.

Records of completed periodic rounds that are collected by Syclo software are maintained in MAXIMO. This information is accessible by area supervisors.

Operational Logs

Operational logs are kept daily and hard copies are sent to the Manager and Supervisors for review.

Operational logs are generated on a daily basis and distributed. Records of field voltages and currents are logged by Honeywell PHD from the GE Energy – WINDAC control system.

Operational Control System

Through the use of GE Energy – WINDAC and WINDRAP control system, operators are able to control equipment function and monitor equipment status in the ESP system. The controls have visual alarms and interconnected DCS alarms to notify OS's of malfunctions or parameter deviations.

The ESP system is controlled via WINDAC and WINDRAP control system. If there is a deviation, the controls have visual alarms and interconnected DCS alarms to notify OS's of malfunctions or parameter deviations so that issues will be addressed.

I. ESP MAINTENANCE PROCESS AND PRACTICES

Maintenance Training

CGS Management requires all personnel responsible for maintaining ESP removal equipment to be trained according to a comprehensive curriculum administered by the CGS Training department or to demonstrate competence.

Maintenance training records are maintained by the CGS training department.

Preventive Maintenance

The area supervisor in charge ensures 100% completion of Preventive Maintenance (PM) work orders.

Records of completed PM work orders are maintained in MAXIMO. This information is accessible by area supervisors.

Corrective Maintenance

Area supervisor is responsible for executing corrective maintenance work orders according to priority, and having a base plan for precipitator outages which will be provided by the planning and scheduling department in the event a scheduled outage is approved. CGS Maintenance shall also be responsible for maintaining execution of a list of preventive maintenance work orders which shall be monitored for completion weekly using AKWIRE scheduling program and MAXIMO for documentation.

Records of completed Corrective Maintenance (CM) work orders are maintained in MAXIMO. This information is accessible by area supervisors.

II. TECHNICAL SERVICES ESP SYSTEM SUPPORT

Process Monitoring

Technical Services monitors process functions and alarms from the plant historian (Honeywell PHD, ESP controls) concerning ESP air lock timing and energy levels of collection fields. This is to ensure ash conveying systems function properly and that all fields are energized.

Technical services uses Honeywell PHD to monitor and review historical process operation of various system parameters. If any fields are found not energized, corrective work orders are initiated in MAXIMO.

Testing and Quality Assurance

Technical Services has preventive maintenance (PMs) to inspect and maintain opacity monitors and CEM operation. Technical Services supports area supervisors concerning periodic monitoring of each ESP, such as volts-amps inspections by field, efficiency of magnitude and frequency of rapping, etc., and shall recommend to area supervisors adjustments to ESP controls to maximize removal efficiency.

Daily records of opacity are maintained and archived in the environmental offices along with all other records required by the CGS Title V operating permit. If baseline opacity is elevated at or near permit limits (limit of 18% average opacity for 24-hours), and adjustments to ESP controls and review of ESP fields in service are not effective in reducing opacity, then Technical Services recommends to area supervisors to request an ESP outage for cleaning and repairs.

Equipment Condition Assessments

Technical Services shall periodically survey each ESP for ductwork insulation integrity and casing leaks using infra-red predictive maintenance (PdM) technology.

Technical Services uses EPRI's Plant View to document and review abnormal PdM technology exams, and coordinates with area supervisors to initiate corrective maintenance work orders if exams are marginal or unacceptable. If possible, CM work orders are scheduled and repairs are completed on-line.

Equipment Inspections

Technical Services supports area supervisors on ESP outages with inspection work orders concerning ESP inlet and outlet ducts, nozzles, and internal alignments.

As a result of inspections of ESP systems during outages, Technical Services recommends repairs for best PM collection.

Environmental Compliance Monitoring

Technical Services is responsible for environmental compliance monitoring and recordkeeping in accordance with the current CGS Title V operating permit.

Daily records of Opacity are maintained and archived in the environmental offices along with all other records required by the CGS Title V operating permit.

ESP BMP QUARTERLY REVIEW – Q1 2020

Introduction / Executive Summary

The Electrostatic Precipitators (ESPs) at Coronado Generation Station (CGS) are operated and maintained in accordance with the “CGS Best Management Practices and Optimization Plan For Existing Electrostatic Precipitator Equipment” dated January 16, 2009.

Operation and maintenance activities have been mostly routine in nature and there were no permit deviations during this reporting period. During the First Quarter of 2020 Unit 1 had a Winter Outage that began November 1 in 2019 Quarter 4 and continued on to February 9, 2020. Unit 1 also had an outage March 4 to March 29. These outages were of sufficient duration to work on the ESPs. In addition, Unit 2 had a Summer Prep Outage starting February 12 which continued into the Second Quarter, and was of sufficient duration to perform work on the ESPs. The completed work on the ESPs during the outages is as detailed below:

1.0 Unit 1 – U1 Winter Outage
(November 1, 2019 – February 9, 2020)

1.1 Engineering Inspections

1.2 Weld Repairs and Electrical Repair Work

1.3 Vacuum out the precipitators and boiler exit duct

1.4 Repair grounded precipitator fields

2.0 Unit 1 – U1 Screens Outage
(March 4 – 29, 2020)

2.1 Repair grounded precipitator fields

3.0 Unit 2 – U2 Summer Prep Outage
(February 12, 2020 – April 24, 2020)

3.1 Weld Repairs and Electrical Repair Work

3.2 Engineering Inspections

3.3 Repair grounded precipitator fields

3.4 Vacuum out the precipitators and boiler exit duct

3.5 Explosive Blasting in Precipitators

ESP OPERATIONAL PROCESS AND PRACTICES

Operational Training

CGS Management requires all personnel responsible for operating ESP equipment to be trained according to a comprehensive curriculum administered by the CGS Training department.

Operator training records are maintained by the CGS training department. Hardcopy records of Best Management Practices (BMPs) training are archived in the environmental offices as they are submitted.

Operating Instructions and Procedures

CGS maintains documented operating procedures. The area supervisors are responsible for ensuring that these procedures are followed consistently by all area personnel authorized to operate ESP equipment.

Area supervisors ensure that operating procedures are accessible, are included in CGS training curriculum and are consistently followed.

Periodic Inspections

The on duty Operations OM Supervisor IV shall assign personnel to complete periodic rounds (daily, weekly, or monthly) to visually inspect ESP equipment for abnormal conditions.

Records of completed periodic rounds that are collected by Syclo software are maintained in MAXIMO. This information is accessible by area supervisors.

Operational Logs

Operational logs are kept daily and hard copies are sent to the Manager and Supervisors for review.

Operational logs are generated on a daily basis and distributed. Records of field voltages and currents are logged by Honeywell PHD from the GE Energy – WINDAC control system.

Operational Control System

Through the use of GE Energy – WINDAC and WINDRAP control system, operators are able to control equipment function and monitor equipment status in the ESP system. The controls have visual alarms and interconnected DCS alarms to notify OS's of malfunctions or parameter deviations.

The ESP system is controlled via WINDAC and WINDRAP control system. If there is a deviation, the controls have visual alarms and interconnected DCS alarms to notify OS's of malfunctions or parameter deviations so that issues will be addressed.

I. ESP MAINTENANCE PROCESS AND PRACTICES

Maintenance Training

CGS Management requires all personnel responsible for maintaining ESP removal equipment to be trained according to a comprehensive curriculum administered by the CGS Training department or to demonstrate competence.

Maintenance training records are maintained by the CGS training department.

Preventive Maintenance

The area supervisor in charge ensures 100% completion of Preventive Maintenance (PM) work orders.

Records of completed PM work orders are maintained in MAXIMO. This information is accessible by area supervisors.

Corrective Maintenance

Area supervisor is responsible for executing corrective maintenance work orders according to priority, and having a base plan for precipitator outages which will be provided by the planning and scheduling department in the event a scheduled outage is approved. CGS Maintenance shall also be responsible for maintaining execution of a list of preventive maintenance work orders which shall be monitored for completion weekly using AKWIRE scheduling program and MAXIMO for documentation.

Records of completed Corrective Maintenance (CM) work orders are maintained in MAXIMO. This information is accessible by area supervisors.

II. TECHNICAL SERVICES ESP SYSTEM SUPPORT

Process Monitoring

Technical Services monitors process functions and alarms from the plant historian (Honeywell PHD, ESP controls) concerning ESP air lock timing and energy levels of collection fields. This is to ensure ash conveying systems function properly and that all fields are energized.

Technical services uses Honeywell PHD to monitor and review historical process operation of various system parameters. If any fields are found not energized, corrective work orders are initiated in MAXIMO.

Testing and Quality Assurance

Technical Services has preventive maintenance (PMs) to inspect and maintain opacity monitors and CEM operation. Technical Services supports area supervisors concerning periodic monitoring of each ESP, such as volts-amps inspections by field, efficiency of magnitude and frequency of rapping, etc., and shall recommend to area supervisors adjustments to ESP controls to maximize removal efficiency.

Daily records of opacity are maintained and archived in the environmental offices along with all other records required by the CGS Title V operating permit. If baseline opacity is elevated at or near permit limits (limit of 18% average opacity for 24-hours), and adjustments to ESP controls and review of ESP fields in service are not effective in reducing opacity, then Technical Services recommends to area supervisors to request an ESP outage for cleaning and repairs.

Equipment Condition Assessments

Technical Services shall periodically survey each ESP for ductwork insulation integrity and casing leaks using infra-red predictive maintenance (PdM) technology.

Technical Services uses EPRI's Plant View to document and review abnormal PdM technology exams, and coordinates with area supervisors to initiate corrective maintenance work orders if exams are marginal or unacceptable. If possible, CM work orders are scheduled and repairs are completed on-line.

Equipment Inspections

Technical Services supports area supervisors on ESP outages with inspection work orders concerning ESP inlet and outlet ducts, nozzles, and internal alignments.

As a result of inspections of ESP systems during outages, Technical Services recommends repairs for best PM collection.

Environmental Compliance Monitoring

Technical Services is responsible for environmental compliance monitoring and recordkeeping in accordance with the current CGS Title V operating permit.

Daily records of Opacity are maintained and archived in the environmental offices along with all other records required by the CGS Title V operating permit.

ATTACHMENT C

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M E M O R A N D U M

TO: Rae Cronmiller, NRECA

FROM: Ralph L. Roberson, P.E.

DATE: June 16, 2023

SUBJECT: Technical Comments on EPA's Proposed Rule: Mercury and Air Toxics Standards Risks and Technology Review – PM CEMS

INTRODUCTION

Recently, the Environmental Protection Agency (EPA) proposed revisions to the Agency's Mercury and Air Toxics Standards (MATS) rule.[1] These revisions are the proposed response of EPA to its previously announced review of its 2020 Risks and Technology and Review (RTR).[2] Among other things, EPA proposes to eliminate the quarterly stack testing option for demonstrating compliance with the filterable particulate matter (fPM) emission standard. If EPA finalizes the rule as proposed, the only compliance option for fPM will be with a PM continuous emission monitoring system (CEMS). Compliance with the proposed emission standard of 0.010 lb/10^6 Btu will be based on 30-day rolling averages computed from hourly PM CEMS data.

The National Rural Electric Cooperative Association (NRECA) asked RLR Consulting LLC (RLR) to review EPA's proposed rule and to assist in preparing technical comments. NRECA asked RLR to focus its effort on the EPA requirement to mandate the use of PM CEMS to demonstrate compliance with the revised fPM emission standard.

REGULATORY DISCUSSION

Section 112(f) of the Clean Air Act (CAA) states, among other things, "if standards promulgated pursuant to subsection (d) and applicable to a category or subcategory of sources emitting a pollutant (or pollutants) classified as a known, probable or possible human carcinogen do not reduce lifetime excess cancer risks to the individual most exposed to emissions from a source in the category or subcategory to less than one in one million, the Administrator shall promulgate standards under this subsection for such category." Then, Section 112(d)(6) requires EPA to "review and revise as necessary

[1] 88 Fed. Reg. 24,854 (April 24, 2023).
[2] 87 Fed. Reg. 7,624 (February 9, 2022).

(taking into account developments in practices, processes, and control technologies), emission standards promulgated under this section no less often than every 8 years." Taken together, these two provisions of the CAA constitute what is termed EPA's Risk and Technology Reviews (RTR). Clearly, Section 112(f) is concerned with health risks and has nothing to do with compliance methods or procedures. Section 112(d)(6) concerns itself with revising numerical standards based on "developments in practices, processes, and control technologies." Thus, there appears to be no legal basis for EPA's proposed elimination of the quarterly stack testing option for demonstrating compliance with the fPM emission standard.

TECHNICAL DISCUSSIONS

The fundamental problem with PM CEMS is, and always has been, an issue of technology. That is, commercially available PM CEMS do not provide a direct measure of PM emissions. By direct measure, we mean that the instrument measures the mass of PM and the volume of flue gas from which that mass of PM was sampled. Rather, commercially available PM CEMS measure some property (i.e., light scatter or beta attenuation[3]) that must be correlated to actual stack PM measurements.

Correlation Testing and Data Range

The procedure and requirements for correlation testing are specified in EPA Performance Specification 11 (PS-11).[4] PS-11 requires a minimum of 15 test runs using the appropriate EPA reference method (e.g., MATS Method 5) spaced over three distinct PM concentrations (i.e., low, mid and high).[5] For the resulting correlation to be useful, these three distinct PM concentrations should span the range of expected concentrations with a target level (i.e., 50 percent of the limit) in the middle of the range.

A PM CEMS correlation curve plots the PM CEMS output on the x-axis and the reference method PM concentration on the y-axis. Reference method PM concentrations (y-axis) are typically expressed in the units of milligrams per actual cubic meter (mg/acm), and "actual" refers to the condition at which the PM CEMS detector operates. EPA is proposing to lower the filterable PM emission limit from 0.030 to 0.010 lb/10^6 Btu.[6] Conversion of 0.010 lb/10^6 Btu to mg/acm requires knowledge of the detector temperature and stack diluent (e.g., CO_2) concentration. If we use a typical CO_2 concentration of 12.5 percent (wet) and a detector temperature of 320 º F, then 0.010 lb/10^6 Btu converts to 7.5 mg/acm. Following EPA's assumption that the unit will

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[3] The EPA statement at 88 Fed. Reg. at 24,872, that a beta gauge "detector measures the amount of radiation emitted by the sample" is categorically incorrect and illustrative of several uninformed statements (e.g., cost estimates) about PM CEMS in the preamble to the proposed rule.
[4] 40 C.F.R. 60, Appendix B.
[5] PS-11 defines "low" to be zero to 50 percent of the maximum PM concentration; "mid" to be 25 to 75 percent of the maximum PM concentration; and "high" to be 50 to 100 percent of the maximum PM concentration. RLR's many years of experience with PM CEMS correlation testing is to equate "maximum PM concentration" with the PM emission limit.
[6] 88 Fed. Reg. at 24,857.

operate at the "target compliance level," which is 50 percent of the emission limit, (0.005 lb/10^6 Btu) we then have a unit operating at 3.75 mg/acm with an equivalent emission limit of 7.5 mg/acm. Not only will it be virtually impossible to conduct correlation testing at <u>three</u> PM concentrations (low, mid and high), it is far from clear that any type of valid PM CEM correlation can be established over such a limited data range. Using 7.5 mg/acm as the emission limit: low becomes 0 to 3.75 mg/acm; mid is 1.88 to 5.63; and high is 3.75 to 7.5 mg/acm. Anyone who believes he or she can regulate and control PM emissions from a coal-fired EGU that precisely has never set foot in such a facility. If EPA finalizes the MATS fPM limit to 0.010 lb/10^6 Btu, there is a much stronger technical argument to eliminate PM CEMS as a compliance option altogether and rely on quarterly stack testing with longer run times for all EGUs.

EPA states that 3-hr stack testing runs are the solution to minimizing both costs and uncertainty associated with the proposed lower fPM emission limit. While 3-hr testing runs may be acceptable for a standard compliance test that consists of three independent test runs, it is quite unreasonable for either PS-11 initial correlation tests and/or response correlation audits (RCAs). As noted above, PS-11 correlation testing requires a minimum of 15 runs and allows the owner/operator to discard up to five runs to improve correlations. Thus, it is not unusual to conduct 20 test runs for the PS-11 initial correlation test. [7]

A 20-run test program with 3-hr test runs will require on the order of 2 weeks. This is an excessive amount of time to take a unit off dispatch and hold constant load conditions for the sake of testing. How ironic it would be to displace renewable generation with a coal-fired EGU for 2 weeks simply to complete EPA-required testing. The increase in stack testing cost will be significant. [8] Granted, longer test runs improve Method 5 accuracy at low PM concentrations. However, longer test runs will neither expand the <u>range</u> of the data nor the <u>quality</u> of the resulting PM CEMS correlations. The range of the data will be limited even with longer test runs, and the robustness on any resulting correlation will be questionable.

<u>Portland Cement Argument</u>

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 mg/dscm.[9] In the MATS RTR proposal, EPA attempts to dismiss comparisons to the Portland Cement rule by asserting that the particle characteristics between the two source categories are different. We agree that the particle

[7] The RCA requires a minimum of 12 individual runs, and also allows owners/operators to discard up to five runs. Thus, 17 individual runs are often performed for an RCA.
[8] RLR Consulting obtained a budgetary cost estimate of $80,000 for conducting PS-11 correlation test with the proposed sample volume requirement of 4 dscm. The budgetary estimate is $30,000 for conducting PS-11 correlation test under the current MATS requirements.
[9] 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.

characteristics may indeed be different; however, 5 to 8 mg/dscm is a low PM concentration regardless of the size, shape, or constituency of the particles.

EPA addressed its concerns in the Portland Cement rule by (1) increasing the emission limit to a range of 7 to 14 mg/dscm, and (2) no longer requiring PM CEMS to demonstrate compliance with the emission limit. If the real problem were, as EPA now claims, (i.e., 1-hr test runs "led to inherent measurement uncertainty"), we initially wondered why EPA did not simply increase the run times as the Agency is proposing to do in the MATS rule? Further research reveals that EPA did examine the effect of longer run times in 2012 Portland Cement rule. However, EPA recognized then that longer run times would not solve the problem created by a very limited data range for the correlation testing associated with a very low emission limit.[10] 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.

As noted earlier, PS-11 specifies the correlation requirements that are applicable to PM CEMS. To satisfy PS-11, the PM CEMS correlation must meet the following statistical criteria:

- The correlation coefficient shall be ≥ 0.85.
- The confidence interval (95%) half range at the median PM CEMS response value must be within 10% of the PM emission limit value.[11]
- The tolerance interval half range at the median PM CEMS response value must have 95% confidence that 75% of all possible values are within 25% of the PM emission limit value.

These PS-11 statistical considerations coupled with the low proposed emission limit clearly played a role in EPA's final decision to forego PM CEMS in the Portland Cement rulemaking. In the final Cement rule, EPA states[12]

> A particular challenge in applying PM CEMS to source emissions monitoring is in measuring the very low PM concentrations associated with a low applicable emissions limit for PM precisely enough to meet the PS 11 correlation requirements. In addition to measurement uncertainty inherent in PM CEMS data, the measurement uncertainty associated with the reference test method (e.g., Method 5) is a significant contributor to successful development of a PM CEMS correlation regardless of the type of PM CEMS used.

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[10] 77 Fed. Reg. 42,368, 42374 (July 18, 2023).
[11] PS-11 states that the points at which the confidence interval and tolerance interval half ranges are evaluated are a function of the form of the regression equation. For linear and logarithmic correlations, the half intervals are evaluated at the mean PM CEMS response.
[12] 77 Fed. Reg. at 42,374.

As noted above, PS 11 specifies acceptable criteria for a correlation directly related to the applicable emissions limit. If we use 7.5 mg/acm for EPA's proposed fPM limit of 0.010 lb/10^6 Btu,[13] the 95% confidence interval would have to be less than or equal to 0.75 mg/acm. Likewise, the tolerance interval would have to be less than or equal to 1.88 mg/acm. We are not aware of any data or technical support that any commercially available PM CEMS is capable of meeting these very tight confidence and tolerance intervals, and EPA cites none. Adding to the challenge of achieving these strict confidence and tolerance intervals is the fact that these intervals will be at or near the method detection limit of the EPA Method 5, even with extended run times. While PS-11 ascribes all of the measurement errors to the PM CEMS, variability in reference method measurements at these low PM concentrations will likely result in numerous PS-11 failures.

PM CEMS and New EGUs

EPA appears to dismiss concerns with PM CEMS measurements at the low PM concentrations that would be required by the proposed emission standard (0.010 lb/10^6 Btu) by stating: (1) PM CEMS are mandated for new EGUs and (2) the revised fPM emission standards for existing EGUs and the fPM for new EGUs are approximately the same (0.010 lb/10^6 Btu v. 0.090 lb/MWh).[14] We have two issues with EPA's use of new EGUs to support PM CEMS at low concentrations.

Assuming PM CEMS are required for new EGUs, EPA's claim is without merit because PM CEMS are not and have never been demonstrated on new EGUs. The reality is there are no new EGUs in operation, and there is never likely to be one. Apparently, EPA agrees because in the Agency's recently signed proposed rule for controlling greenhouse gas emissions from the power sector, EPA explains not revising the NSPS for newly constructed fossil-fuel-fired steam generating units with the following sentence: "[t]his is because the EPA does not anticipate that any such units will construct or reconstruct and is unaware of plans by any companies to construct or reconstruct a new coal-fired EGU."[15] Supporting the proposed use of PM CEMS at low fPM concentrations by stating the requirement is consistent with a theoretical requirement for new EGUs that have not been built and will never be built is no support at all.

Discussion of PM CEMS Costs

EPA's statement, "not all EGU owners or operators chose the most cost-effective means of demonstrating compliance with the fPM emission limits"[16] is as insulting as it is incorrect. In 2015, we were asked by an EGU owner to estimate the cost over a 10-year

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[13] Base on a stack CO_2 concentration of 12.5% (wet basis) and a PM CEMS detector temperature of 320 º F.
[14] For the MATS rule, a new EGU is defined as one that commenced construction after May 3, 2011.
[15] 88 Fed. Reg. 33,245 (May 23, 2023).
[16] 88 Fed. Reg. 24,872 (April 24, 2023).

period of demonstrating compliance with the MATS fPM emission limit based on (1) quarterly stack testing and (2) PM CEMS. For stack testing, we estimated a total cost of $260,000 (i.e., 10 yr. x 4 quarters x $6,500). The 10-year cost for PM CEMS was $479,500. The PM CEMS estimate included $90,000 capital (representative of an extractive light scatter instrument), $35,000 for initial PS-11 correlation test, $90,000 for three response correlation audits (RCA), $45,500 for seven relative response audits (RRA), and about $20,000 per year for routine maintenance and spare parts. Note that our PM CEMS estimate did <u>not</u> include the cost of three PM spiking events, which would significantly increase the cost of the PM CEMS option. Also, neither cost estimate assumed 3-hr test runs. Longer test runs will increase the cost of quarterly stack tests; however, we believe the cost increase would be greater for PM CEMS because so many more test runs are involved.

We also disagree with EPA statements regarding stack testing costs. EPA states, "annual cost for M5 testing with 3 hour run duration is estimated to be $85,127 ($82,000 for testing, and $3,127 for 24 hours of site technical support); quarterly testing using M5I with runs of similar duration is estimated to be $107,127."[17] RLR obtained a cost estimate of $38,000 from a stack testing company to conduct four quarterly stack tests and collect a minimum sample volume of 4 dscm for each run. EPA digs a deeper hole with its absurd M5I annual estimate of $107,127. As a threshold matter, M5I is not allowed under the MATS rule because M5I specifies a probe and filter temperature of 250 º F whereas the MATS rule requires a probe and filter temperature of 320 º F. Assuming EPA were to correct this technical oversite, EPA could never explain how M5I testing would or should cost $22,000 more per year than M5 testing. In other words, EPA grossly inflates its stack testing cost estimates in attempting to make PM CEMS appear more palatable.

<u>Qualitative Aerosol Generator</u>

EPA is correct in stating that for several years the Electric Power Research Institute (EPRI) funded research associated with the development of the Qualitative Aerosol Generator (QAG). The QAG could generate particles of uniform size distribution at precisely known concentrations. The QAG contained components (i.e., mass flow meter) whose calibrations were traceable to the National Institute of Standards and Technology (NIST). However, it was never clear whether the PM aerosol concentration could be shown to be "NIST traceable."

More importantly, EPRI ceased funding QAG research circa 2018. Among the reasons for stopping the research were (1) the field tests had become increasingly complex and expensive and (2) utility-funders lost interest primarily because of EPA's lack of response despite several attempts by EPRI to get EPA involved in a project that sought to make PM CEMS correlations more efficient. We find it incredulous that EPA would dredge up an EPRI project that the Agency never showed any support for and attempt to use that defunct project to support this rulemaking proposal.

[17] Ibid at 24873.

EPA Random Error Memo

EPA states that the impact of sampling times and random errors on measurable emission limits is described in a memorandum in the docket.[18] The Memorandum statement, "2 mg/dscm for a one-hour test run (which is equivalent to a mass per heat input value of 0.0082 lb/mmBtu)," is simply incorrect. A fPM concentration of 2 mg/dscm is approximately 0.0021 lb/10^6 Btu assuming nominal CO_2 concentration of 10.5 % (dry).

The following Memorandum statement "one can calculate the range of the contribution of random error to the total PM CEMS tolerance to be between thirty-six and seventy-three percent" may or may not be incorrect. The Memorandum provides neither a reference nor a method for how random error is defined or calculated. Likewise, there are no text or equations to support the results shown in Table 1. Frankly, the Agency should be embarrassed to include in a rulemaking docket a 2-page Memorandum that is so poorly explained or substantiated.

CONCLUSIONS

First, RLR is not certain the RTR process affords EPA the latitude to make changes to compliance determination procedures. However, as discussed above, the technical justification for mandating PM CEMS, especially if EPA were to lower significantly the fPM standard (as it currently has proposed) is deeply flawed and fraught with several incorrect or inaccurate statements, both concerning the ability to obtain meaningful correlations over a limited data range and the cost of PM CEMS. Thus, for the reasons explained in this memorandum, EPA would be well advised to maintain the quarterly stack testing option for fPM in its MATS rule. Moreover, if EPA were to lower the fPM limit to 0.01 lb/10^6 Btu, EPA should follow the precedent the Agency set in the Portland Cement rule and withdraw PM CEMS as a compliance testing option. Periodic, quality stack tests will be a much better indicator of compliance than continuous data of questionable quality.

If you have any questions regarding our technical comments or require additional information, please do not hesitate to contact me (919) 696-7008 or rlph.roberson@gmail.com.

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[18] "PM CEMS Random Error Contribution by Emission Limit," Docket ID No. EPA-HQ-OAR-2018-0794-0794 (hereinafter "Memorandum').