MEMORANDUM

FROM:	Sarah Benish, Nick Hutson, Erich Eschmann U.S. EPA/OAR
TO:	Docket ID. No: EPA-HQ-OAR-2018-0794
DATE:	January 2024
SUBJECT:	2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category (2024 Technical Memo)

This memorandum documents the updates and revisions to the 2023 technology review the U.S. Environmental Protection Agency (EPA) conducted in accordance with section 112(d)(6) of the Clean Air Act to identify developments in practices, processes, and control technologies applicable to sources subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for coal- and oil-fired electric utility steam generating units (EGUs) (40 CFR 63, subpart UUUUU).[1] Most of the updates presented in this memorandum to the 2023 Proposed Technology Review are the result of information received in public comments. This memorandum is organized as follows:

1. Filterable Particulate Matter (fPM) Emission Limit
    a. Assessment of Additional Data
    b. Unit List Review
    c. PM Controls Upgrade Costs and Emission Reductions
2. Oil-fired EGU Emission Limits
    a. Summary
    b. Background on Winter Storm Elliot
    c. Emission Performance Evaluation of Oil EGUs Operating in New England During Winter Storm Elliot
3. Mercury Limit for Lignite-Fired EGUs
    a. Hg Emissions from Coal-fired EGUs
    b. Review of the Hg Emission Standard for Lignite-Fired EGUs

[1] 88 FR 24854; April 14, 2023.

c. Determination of an Achievable Hg Emission Standard for Lignite-Fired EGUs
d. Cost of Meeting the Revised Emission Standard

4. Transparency of PM CEMS
    a. Case Study 1
    b. Case Study 2

The following attachments supporting the analysis presented in this memorandum are available in the docket:

- Attachment 1: Excel spreadsheet with unit list of EGUs, cost and emission reduction assumptions, and calculations for the assessed limits. Note: this file contains rounded numbers;
- Attachment 2: pdf of Jupyter notebook plotting additional fPM data; and
- Attachment 3: Excel spreadsheet of hourly PM CEMS data shown in section 4.

Acronyms:

Btu	British Thermal Units
C2G	Coal to gas conversion
CAA	Clean Air Act
CEDRI	Compliance and Emissions Data Reporting Interface
CEMS	continuous emission monitoring systems
DFO	Distillate fuel oil
EGU	electric utility steam generating unit
EIA	Energy Information Administration
ESP	electrostatic precipitator
FERC	Federal Energy Regulatory Commission
FF	fabric filter
FGD	flue gas desulfurization
fPM	filterable particulate matter
GWh	gigawatt-hour
HAP	hazardous air pollutants(s)
HCl	hydrogen chloride
HF	hydrogen flouride
Hg	mercury
Hg^0	elemental Hg vapor
ICR	Information Collection Request
IPM	Integrated Planning Model

ISO	Independent system operator
ISO-NE	Independent system operator New England
lbs/yr	pounds per year
LEE	low emitting EGU
MATS	Mercury and Air Toxics Standards
MM	million
MW	megawatt
NEEDS	National Electric Energy Data System
NERC	North American Electric Reliability Corporation
NESHAP	national emission standards for hazardous air pollutants
OAQPS	Office of Air Quality Planning and Standards
PM	particulate matter
RFO	Residual fuel oil
RTO	Regional transmission organization
RTR	risk and technology review
SO_2	sulfur dioxide
TBtu	trillion British thermal units
tpy	tons per year
WebFIRE	Web Factor Information Retrieval System

1. Filterable Particulate Matter (fPM) Emission Limit

a. Assessment of Additional Data

Commenters noted that the Agency's fPM review only included one to two quarters of data for a vast majority of EGUs. As described in the 2023 Technology Review memorandum (Docket ID No. EPA-HQ-OAR-2018-0794-5789), data selection aimed to include recent compliance years during quarters with typically higher electricity demand (winter and summer). Since proposal, the EPA reviewed all available historical fPM compliance data for 62 EGUs at 33 facilities.[2] The additional data are available in the docket[3]. While the Agency collects quarterly compliance reports across the fleet, obtaining the data available on WebFIRE or CEDRI is time-consuming, requiring separate file downloads for each quarter for each EGU and

[2] Revised data for 2019 Q3 submitted by White Bluff Unit 1 were also updated.

[3] Excel spreadsheets for each facility are available in Docket ID No. EPA-HQ-OAR-2018-0794 at *regulations.gov*. A subset of available data for nine facilities in Region 7 (George Neal North, George Neal South, Gerald Gentleman, John Twitty Energy Center, Louisa, Nebraska City, Sheldon, Walter Scott Jr Energy, and Whelan Energy Center) are provided in one Excel spreadsheet (only passing test results were used in the updated analysis).

transcribing the data from a portable document format (pdf) file into an Excel file. Data reviewed includes EGUs identified in the 2023 Proposal as needing to install fPM upgrades to meet the proposed fPM limit of 0.010 lb/MMBtu. The Agency acknowledges that this revised analysis was based on one quarter of data for 48 EGUs and two quarters of data for 155 EGUs. The vast majority of these EGUs with one or two quarters of data indicate average fPM rates below 0.010 lb/MMBtu and therefore have very low or minimal costs estimated to meet the proposed and finalized fPM limit. However, if the Agency were able to pull data for every quarter for every EGU in this analysis, it would only lower the lowest achieved fPM rate, therefore potentially decreasing PM upgrade costs to meet a lower fPM limit. This is because we select the lowest value of all quarterly 99th percentiles as the lowest achieved fPM rate. For example, if we were to calculate the 99th percentile for an additional quarter of data and that new value is less than the previous lowest achieved fPM rate, we would then select the new value as the lowest achieved fPM rate. Attachment 1 contains a spreadsheet with a column indicating which EGUs had additional data reviewing (see "Additional Data Review since Proposal" column (either yes or no) in the "Unit-Level Information and Inputs" sheet) and Attachment 2 includes the Python plotting code written to plot and assess the additional data that is presented below. During this additional review, the Agency was unable to locate some fPM compliance reports or specific information, as identified in Table 1.

Table 1. EGUs with unavailable data or other missing information encountered during the EPA's review of additional fPM compliance data.

Plant Name	**NEEDS[4] Unique ID**	**Description**
Big Stone	6098_B_1	2017 & 2018 fPM compliance reports contain stack averages and not individual stack test runs
Colver Power	10143_B_ABB01	Complete test reports after 2019 not found in CEDRI; June 2022 test result indicates 0.000859 lb/MMBtu
Coronado	6177_B_U1B, 6177_B_U2B	fPM continuous emission monitoring system (CEMS) compliance reports do not contain 30-day running average for certain days: 5/31/21, 5/31/22, and 8/31/22
D B Wilson	6823_B_W1	Unable to locate 2017 Q2 and Q3 fPM compliance reports

[4] The National Electric Energy Data System (NEEDS) database contains generation unit information used in the EPA's power sector modeling. See *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs*.

Foster Wheeler	10343_B_SG-101	Unable to locate fPM compliance reports in CEDRI after 2020
Gavin Power, LLC	8102_B_1, 8102_B_2	Unable to locate additional fPM compliance data in CEDRI
Martin Lake	6146_B_1	Unable to locate 2019 Q1 fPM CEMS compliance data
Red Hills	55076_B_AA01, 55076_B_AA02	Unable to locate several quarters of quarterly stack test fPM compliance data
San Miguel	6183_B_SM-1	Unable to locate quarterly stack test fPM compliance data in CEDRI after 2018 Q1
St Nicholas Cogen	54634_B_1	Unable to locate fPM compliance data for 2022 and 2023 in CEDRI
Westwood Generation	50611_B_031	Unable to locate individual stack test runs as compliance reports only contain stack averages
Whelan Energy	60_B_1	Unable to locate additional fPM compliance data in CEDRI

The review of the additional compliance data reveal most EGUs had previously demonstrated much lower fPM rates than estimated for the 2023 Proposal, but also exhibited large variability within quarters and annually. Commenters similarly conveyed their observations that the data illustrate a large degree of temporal variation in the 30-day averages, and the fact that the emissions happened to be low during a single quarter does not indicate that that same level of performance can be consistently achieved over time. For instance, at D B Wilson, as shown in Figure 1 (as well as Case Study #16 in Attachment 2), the PM CEMS 30-boiler operating day rolling average fPM data show consistent quarterly emission rates of approximately 0.016 lb/MMBtu from mid-2020 to the end of 2022, well below the 0.030 lb/MMBtu standard. After this time, 30-day rolling average fPM rates dropped sharply in early 2023 to approximately 0.007 lb/MMBtu. Data from D B Wilson also show rapidly decreasing 30 boiler operating day rolling average fPM rates from approximately 0.025 lb/MMBtu in mid-2017 to approximately 0.009 lb/MMBtu in early 2019. The average and median of the PM CEMS data are very close to the 2023 Proposal fPM assumption for D B Wilson of 0.015 lb/MMBtu. The review of additional fPM compliance data find a revised lowest achieved fPM rate for the 2024 Final Rule of 0.010 lb/MMBtu, a fPM rate this facility has achieved on multiple occasions for long periods of time. However, as the average fPM rate of all available data is 0.0148 lb/MMBtu,

it is likely this EGU will need to invest in some O&M of its ESP in order to reduce the fPM rate variability to meet a lower limit consistently.

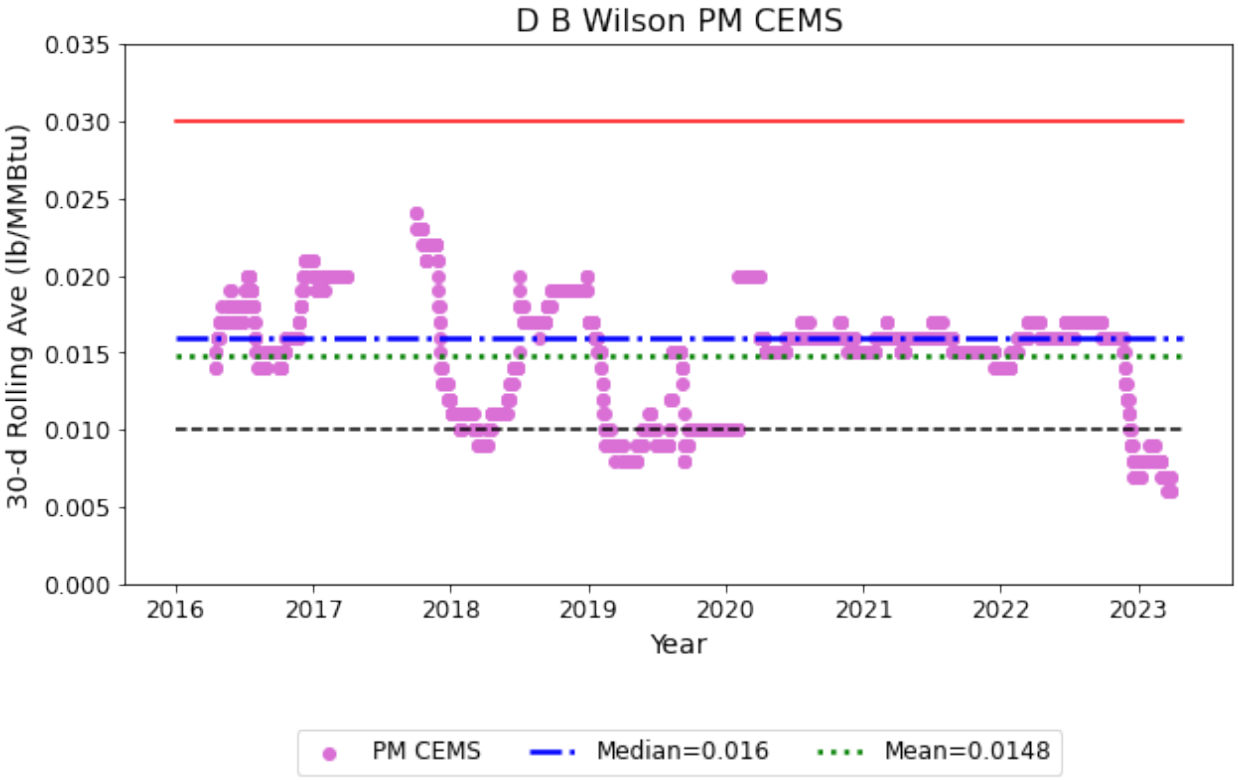

Figure 1. fPM compliance data from D B Wilson from 2016-2023.

Similarly, PM CEMS data from Marion, as shown in Figure 2 (Case Study #14 in Attachment 2), show 30 boiler operating day rolling average values ranging from less than 0.005 lb/MMBtu to approximately 0.026 lb/MMBtu from 2017 to 2023, but the data are highly variable within a quarter, rapidly ramping up and down. The median and mean of the PM CEMS data is approximately 0.014 lb/MMBtu, slightly lower than the 2023 Proposal assumption of 0.017 lb/MMBtu. The revised lowest achieved fPM rate is 0.005 lb/MMBtu, but it is clear that this rate is not representative of its "normal" average operating conditions.

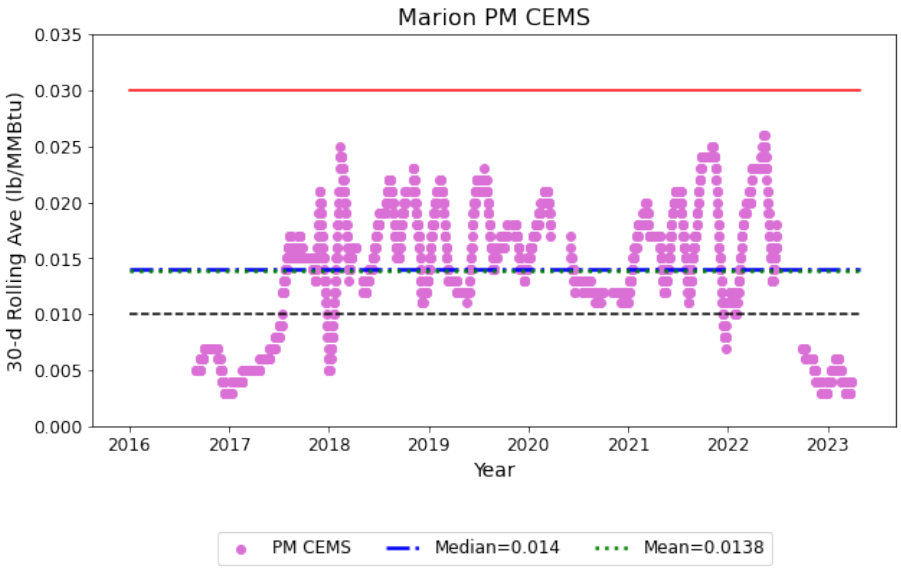

Figure 2. fPM CEMS compliance data for Marion from mid-2016 through the beginning of 2023.

Intermittent stack testing data also reveal highly variable fPM averages. For instance, data from Red Hills, shown in Figure 3 (Case Study #29 in Attachment 2), reveal variable fPM rates, especially in the last several quarters: as low as 0.003 lb/MMBtu in 2021 Q1 to approximately 0.027 lb/MMBtu in 2022 Q3. The 2023 Proposal assumption for Red Hills was 0.004 lb/MMBtu and the revised assumption for the 2024 Final Rule is 0.0037 lb/MMBtu. However, these proposed and revised lowest demonstrated fPM rates are not met consistently, even with controlled "snapshot" testing conditions during stack testing.

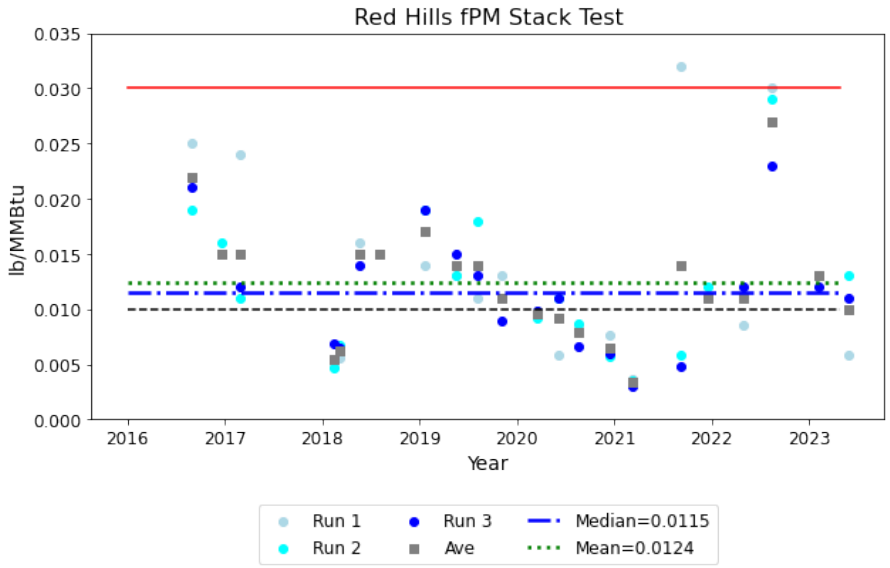

Figure 3. Red Hills fPM stack test data from mid-2016 to early 2023.

As a result of the additional data review, the Agency determined that the lowest achieved fPM rate is not representative of actual emissions on average for use in emission reduction and cost-effectiveness calculations. However, the lowest achieved fPM rate remains effective for identifying EGUs that have historically achieved lower fPM rates, despite not being required to do so and without additional capital investments. The updated analysis first, identifies EGUs that have not previously demonstrated an ability to meet a lower fPM limit using the lowest achieved fPM rate or average fPM rate; and second, uses the average fPM rate calculated from all available data (either 30-boiler operating day rolling averages or individual stack test runs depending on compliance method) to account for unit variability and to determine emission reductions on average anticipated from a lower fPM limit. The revised lowest achieved fPM rate and average fPM rate for each EGU, as well as the number of quarters these rates are based on, are located in the "Unit-Level Information and Inputs" sheet of Attachment 1.

b. Unit List Review

The analysis for the proposal considered 275 coal-fired EGUs expected to be operational on January 1, 2029. In reviewing the unit list for the final rule, the EPA considered comments submitted to the docket. Commenters on the proposal stated the analysis supporting the proposed fPM limit of 0.010 lb/MMBtu and the more stringent option of 0.006 lb/MMBtu excluded EGUs that may not have retired or ceased burning coal by the compliance deadline of 2029, which

commenters claimed have generally higher PM rates compared to the assessed fleet. Commenters also noted the analysis included some units that have plans to convert to gas in 2025, excluded some EGUs with no current plans to retire or switch to gas, and included some EGUs with federally enforceable retirement dates of December 31, 2028. Commenters correctly stated there was no 2017 data for Entergy's five EGUs (RS Nelson, White Bluff, and Independence), but mistakenly stated only White Bluff Unit 1 had 2021 Q1 data. Commenters from Louisville Gas and Electric Company and Kentucky Utilities Company (LGE-KU, part of Docket ID No. EPA-HQ-OAR-2018-0794-5989) noted that the last 30-boiler operating day rolling average or average of the 30-day rolling averages was used for their facilities, however this was not the case as 99th percentiles of each quarter of data were computed and coincidently matched the last 30-day rolling average.

In updating this analysis for the final rule, the Agency used the most recent version of the National Electric Energy Data System (NEEDS) available at the time (see 8-7-23 version at https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs), which incorporates comments received on the proposed rule. This version excludes 29 EGUs with plans to convert to gas or retire by 2029 and adds 51 EGUs that were not included in the proposal analysis (either due to changes in announced retirement dates or errors in the original analysis) if subject to MATS and operating on January 1, 2029. Table 2 summaries the EGUs that were removed or added for the final PM analysis. Units identified in Appendix A from the 2023 Technology Review memorandum (Docket ID No. EPA-HQ-OAR-2018-0794-5789) were added to the analysis unless the EGU has announced plans to retire or convert to gas before 2029 or if no data were available in CEDRI. The revised analysis considers 296 coal-fired EGUs expected to burn coal by the start of the compliance period. Attachment 1, accompanying this 2024 Technical Memo docket entry, includes a list of the EGUs in the "Unit-Level Information & Inputs" sheet.

Table 2. EGUs that were added or removed from the final PM analysis since proposal.

Plant Name	**NEEDS Unique ID**	**Added or Removed?**	**Notes**
AES Petersburg	994_B_3, 994_B_4	Removed	C2G conversion in 2025

Allen S King	1915_B_1	Added	Retirement date changed from 2028 to 2029
Barry	3_B_5	Added	No longer retiring in 2028
Belle River	6034_B_1, 6034_B_2	Removed	C2G conversion in 2026, 2025
Big Cajun 2	6055_B_2B3	Added	Retirement date changed from 2027 to 2032
Bowen	703_B_1BLR, 703_B_2BLR	Added	No longer retiring in 2028
Brame Energy Center	6190_B_2	Removed	C2G/Retiring in 2028
Brame Energy Center	6190_B_3-1, 6190_B_3-2	Added	No longer retiring in 2027
Brunner Island	3140_B_1, 3140_B_2	Removed	C2G conversion in 2021
Cayuga	1001_B_1, 1001_B_2	Added	Retirement date changed from 2028 to 2029
Clay Boswell	1893_B_3	Added	Historical compliance for multiple units that have since retired
Colstrip	10784_B_BLR1	Added	Data were not available for proposal
Cope	7210_B_COP1	Removed	C2G conversion in 2019
Craig	6021_B_C2	Added	Retirement date changed from 2028 to 2029
Cross	130_B_2	Added	Reviewed CPMS data
Dave Johnston	4158_B_BW43	Removed	Retiring in 2027
E C Gaston	26_B_5	Removed	C2G conversion in 2028
E W Brown	1355_B_3	Added	Retirement date changed from 2028 to 2029
FirstEnergy Bay Shore	2878_B_1	Added	Converted lb/MWh
FirstEnergy Harrison Power Station	3944_B_1, 3944_B_2, 3944_B_3	Added	Converted lb/MWh
FirstEnergy Fort Martin Power Station	3943_B_1, 3943_B_2	Added	Converted lb/MWh
Harrington	6193_B_063B	Removed	C2G conversion in 2024
Hayden	525_B_H1	Added	Retirement date changed from 2028 to 2029

John W Turk Jr Power Plant	56564_G_SN-01	Added	Misnamed unit ID led to data unable to be pulled for proposal
La Cygne	1241_B_1	Added	Retirement date changed from 2025 to 2032
Marshall	2727_B_1, 2727_B_2	Added	Retirement date changed from 2026 to 2029
Mayo	6250_B_1A, 6250_B_1B	Added	Retirement updated to 2029
Morgantown Energy	10743_B_CFB1, 10743_B_CFB2	Removed	Not subject to MATS (capacity is 25 MW)
Muscatine Plant #1	1167_B_8	Added	No longer retiring in 2023
Muskogee	2952_B_6	Added	Converted CPMS data, started stack testing in 2020
Naughton	4162_B_1, 4162_B_2	Removed	Retiring in 2025
North Omaha	2291_B_5	Removed	Switching to gas in 2026
Pawnee	6248_B_1	Removed	C2G conversion in 2026
Prairie State Generating Station	55856_G_PC1, 55856_G_PC2	Added	Misnamed unit ID led to data unable to be pulled for proposal
R D Green	6639_B_G1, 6639_B_G2	Removed	C2G conversion in 2022
Roxboro	2712_B_4A, 2712_B_4B, 2712_B_1, 2712_B_2, 2712_B_3A, 2712_B_3B	Added	1, 2: Retirement date changed from 2028 to 2029 3A, 3B: Retirement date changed from 2027 to 2034 4A, 4B: Retirement date changed from 2027 to 2034
Scherer	6257_G_1, 6257_B_3	Added	Retirement date changed from 2028 to 2029
Sooner	6095_B_1	Added	Converted CPMS data
Talen Energy Montour	3149_B_1, 3149_B_2	Removed	C2G conversion in 2025
TES Filer City Station	50835_B_1, 50835_B_2	Removed	Retiring in 2025
T S Power Plant	56224_B_BLR100	Removed	C2G conversion in 2022

Virginia City Hybrid Energy Center	56808_G_1, 56808_G_2	Added	Misnamed unit ID led to data unable to be pulled for proposal
Wateree	3297_B_WAT1, 3297_B_WAT2	Added	Retirement date changed from 2028 to 2029
Welsh	6139_B_1, 6139_B_3	Removed	Retiring in 2028
White Bluff	6009_B_1, 6009_B_2	Removed	According to Attachment B from the Class of 85 comments, both units at White Bluff are subject to federally enforceable requirements to cease coal combustion no later than December 31, 2028.
Williams	3298_B_WIL1	Added	Retirement changed from 2028 to 2029
Winyah	6249_B_1, 6249_B_2, 6249_B_3, 6249_B_4	Added	Converted CPMS data

The EPA previously evaluated select quarterly fPM compliance data for coal-fired EGUs from 2017 to 2021. For each quarter of data for an EGU, the 99th percentile of 30-day rolling average fPM rates (for EGUs demonstrating compliance with PM CEMS, removing invalid data flags) or 99th percentile of all individual test runs (for EGUs using stack testing) was computed. A scatterplot ranking the assessed fPM rates for the coal-fired EGU fleet was shown in Figure 1 in the 2023 Proposal, showing EGUs are reporting fPM emissions well below the 0.030 lb/MMBtu fPM limit. Using the expanded compliance data described above, this figure was updated, as shown in Figure 4 in this document. This updated figure shows that 93 percent of EGUs have previously demonstrated an ability to meet a fPM limit of 0.010 lb/MMBtu, up from 91 percent shown in the 2023 Proposal.

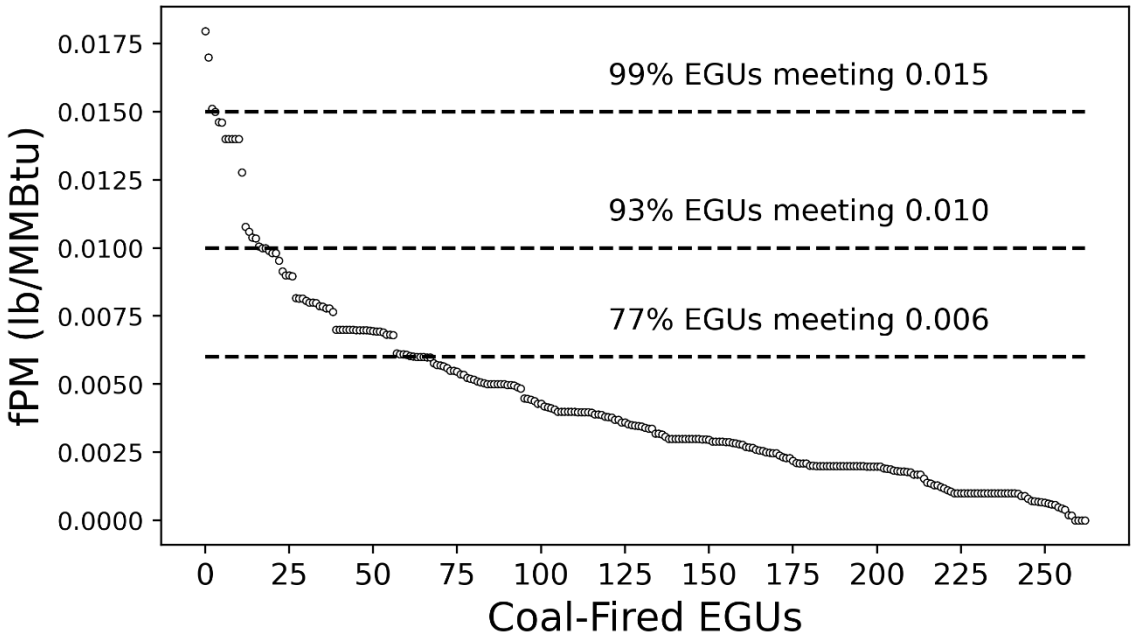

Figure 4. fPM emission rates from coal-fired EGUs ranked, from left to right, from highest fPM emitting to lowest fPM emitting. The dashed lines show the percentage of units that have previously demonstrated emission rates below 0.015, 0.010, and 0.006 lb/MMBtu.

The fPM rate used in the costs, emission reduction, and cost effectiveness calculations in the proposal for each EGU was defined as the minimum value of all available quarterly 99th percentile values (*e.g.*, "lowest quarter's 99th percentile"). While called the "baseline fPM rate" or "baseline," this rate more accurately represents the largest fPM rate in the lowest-emitting quarter with its current control configuration. As commenters noted, and the EPA agrees with based on the data review conducted in section 1a of this technical memorandum, the "baseline fPM rate" is not representative of average operations for most EGUs. Therefore, for this final rule, we redefine the "baseline fPM rate" as the "lowest achieved fPM rate." The "lowest achieved rate" represents the highest fPM rates observed in the lowest-emitting quarter (not the lowest fPM rate measured during the quarter) and thus may overestimate the "lowest achieved rate" in reality for some EGUs since the EPA was unable to review all historical fPM compliance data. As described above, if the Agency evaluated all historical fPM compliance data, the "lowest achieved fPM rate" could only be potentially lower.

c. PM Controls Upgrade Costs and Emission Reductions

Information submitted to the docket during the public comment period informed the revisions in PM control costs. The schematic in Figure 5 summarizes the PM upgrades assumed in the cost-effectiveness analysis and modeling of the final rule based on how the lowest achieved fPM rate and average fPM rate relate to the fPM rate being analyzed.

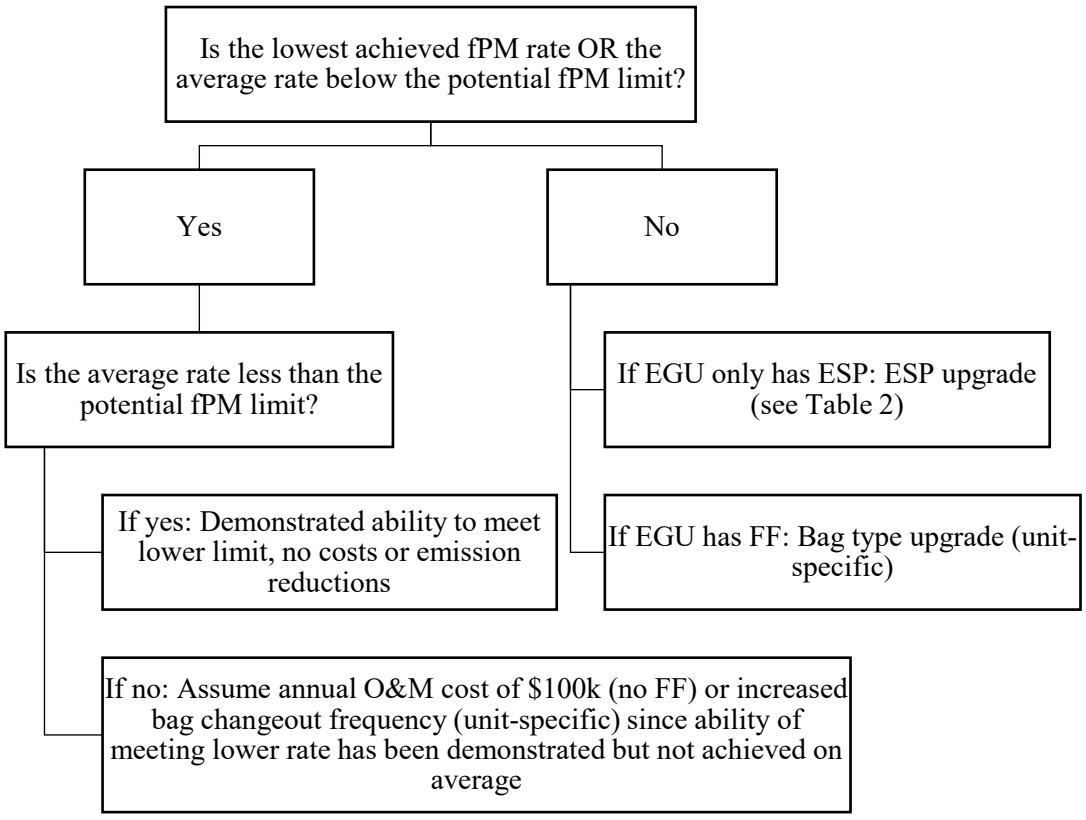

Figure 5. Updated PM control assumptions.

The updated costs for ESP upgrades and new FF installations and comparison to those from the proposal are summarized in Table 3 (all 2019$ unless otherwise noted). The EPA's assumptions for upgrades to existing ESPs for the proposal were based on a report prepared by Sargent and Lundy for the EPA titled "PM Incremental Improvement Memo" (Docket ID No. EPA-HQ-OAR-2018-0794-5836). For this final rule, the ESP upgrade costs and effectiveness were updated based on comments submitted to the docket. For the fPM limit of 0.006 lb/MMBtu,

we have updated the control assumptions to upgrade the existing PM controls instead of assuming all EGUs without FFs to install FFs.

For EGUs with existing ESPs that have demonstrated an ability to meet a lower fPM rate but do not do so on average, the EPA included an "Additional O&M" cost assumption in this final rule. This analysis assumes that this group of EGUs would be able to comply with the final rule at a cost of $100,000 per year (2022$). This additional cost represents increased vigilance in maintaining ESP performance and includes technician labor to monitor performance of the ESP and to periodically make typical repairs (*e.g.*, replacement of failed insulators, damaged electrodes or other internals that might fail, repairing leaks in the ESP casing, ductwork or expansion joints, and periodic testing of ESP flow balance and any needed adjustments). This cost estimate is based on an assumption of 20 labor hours per week at $65/hour dedicated specifically to ESP monitoring and maintenance, plus an additional 50 percent for materials. Materials might include insulators, electrodes or other ESP internal parts, material needed to repair leaks in ductwork or casings, or equipment and materials to test and address flow imbalances.

Table 3. Cost Assumptions in the Proposed and Final rule.

	Without Existing FF					With Existing FF
	Additional O&M	Minor ESP Upgrades	Typical ESP Upgrades	ESP Rebuild	New FF (6.0A/C Ratio)	Upgrade FF Bags
Proposal (reduce to limit)	--	$16.5/kW 7.5% reduction	$55/kW 15% reduction	$88/kW 40% reduction	Unit-specific	Unit-specific
Final (reduce to limit)	$100,000/yr (2022$)	$20/kW 20% reduction	$40/kW 40% reduction	$80/kW 55% reduction	Unit-specific (no change)	Unit-specific (no change)

For units with an existing ESP and without an existing FF, we assumed the ESP upgrades in Table 3 would be necessary to reduce fPM by the levels specified in Table 3.

For EGUs with an existing FF demonstrating the ability to meet a lower limit but not meeting the potential limit on average, we assumed an increased bag changeout frequency (unit-specific) capable of reducing fPM to the limit. Some EGUs that have a FF in addition to other PM controls that have demonstrated an ability to meet a lower limit but are not doing so on average were erroneously excluded from increased bag changeout frequency cost calculations. In these instances, a value of $100,000 is used. This error is limited to the analysis of the 0.006 lb/MMBtu limit and impacts two units: Walter Scott (1082_B_3) and Trimble County (6071_B_1). The $100,000 estimate assumed here is likely conservative, however, as the mean (approximately $44,000) and median (approximately $22,000) costs for increased bag change frequency calculated for the EGUs (see "FF Upgrade Estimated Costs" tab in Attachment 1) are much lower than $100,000.

For EGUs with an existing FF that have not previously demonstrated an ability to meet a lower limit, we assumed a unit-specific bag upgrade to reduce fPM to the limit. These costs are listed in the "FF Upgrade Estimated Costs" sheet of Attachment 1.

For EGUs without an existing FF or ESP that have not previously demonstrated to meet a lower limit, we assumed a FF install would be necessary, reducing average fPM rates by 90 percent, down to a lowest possible rate of 0.002 lb/MMBtu. These FF-specific costs assumptions for EGUs requiring them are provided in the "FF Install Estimated Costs" sheet of Attachment 1.

Filterable PM emission reductions were calculated using the difference between the unit-specific average fPM rate and the various fPM limits (or new assumed fPM rate, using the assumptions above), as shown in Equation 1:

$$fPM\ reductions\ (tons) = \left[Average\ fPM\ rate\ \left(\frac{lb}{mmBtu}\right) - new\ fPM\ rate\left(\frac{lb}{mmBtu}\right)\right] * Average\ Annual\ Heat\ Input\ \left(\frac{mmBtu}{year}\right) * \frac{1\ ton}{2000\ lb}$$

These fPM reductions were translated into non-Hg HAP metals using emission factors, available in the "Metals Ratios" sheet of Attachment 1. Table 4 summarizes the updated PM analysis, including total emission reductions obtained at affected units for fPM, fPM2.5, and speciated non-Hg HAP metals for the three potential limits, as well as cost-effectiveness.

Table 4. Results of Updated PM analysis for three potential limits

Assessed Limits (lb/MMBtu)	**0.015**	**0.010**	**0.006**

Number of EGUs		11	33	94
Capacity (GW)		4.7	14.1	41.3
Annualized Costs ($M)		38.8	87.2	398.8
Emission Reductions (tons/year)	fPM	1258	2526	5849
	fPM2.5	676	1307	2951
	Total non-Hg metal HAP	3.0	8.3	22.7
	As	0.17	0.36	0.87
	Be	0.01	0.02	0.05
	Cd	0.03	0.05	0.11
	Co	0.03	0.09	0.27
	Cr	0.49	2.11	5.99
	Mn	0.83	1.43	3.72
	Ni	0.32	0.98	2.71
	Pb	0.25	0.43	0.95
	Sb	0.06	0.13	0.29
	Se	0.80	2.66	7.67
Cost-Effectiveness ($/lb)	fPM	15.4	17.3	34.0
	fPM2.5	28.7	33.4	67.5
	Total non-Hg metal HAP	6,500	5,280	8,790
	As	117,000	121,000	228,000
	Be	2,560,000	2,140,000	3,680,000
	Cd	689,000	868,000	1,800,000
	Co	734,000	465,000	727,000
	Cr	39,400	20,600	33,200
	Mn	23,400	30,500	53,500
	Ni	60,100	44,600	73,400
	Pb	79,000	102,000	209,000
	Sb	310,000	346,000	681,000
	Se	24,300	16,300	26,000

2. **Oil-Fired EGU Emission Limits**

a. Background

The Agency finalized the limited-use oil-fired subcategory in the 2012 MATS Final Rule (77 FR 9304). The limited-use liquid oil-fired subcategory is defined in 40 CFR 63.10042 as an electric utility steam generating unit with an annual capacity factor when burning oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-

month block contiguous period commencing on the first of the month following the compliance date. The limited-use oil-fired subcategory was finalized because commenters indicated these units were a different class and type because many of them were only called to service to address reliability issues associated with, for example, natural gas curtailments. Commenters further indicated these units are different because of the generally infrequent use and the sporadic, and at times frequent, start-up and shut down periods (*e.g.,* they are often only required to run a couple of hours). These factors would lead to differences in emission characteristics for these units such that a numeric standard based on base load units would not likely be achievable during the very limited time these limited use oil-fired units operate. Instead, the Agency finalized work practice standards consisting of burner tune-ups, keeping records of activity and fuel usage, and submitting a report for each tune-up conducted.

In the 2023 Proposal, the EPA found the annual capacity factors of most continental liquid oil-fired EGUs to be low (3 percent in 2021). Additionally, there were only two continental liquid oil-fired EGUs with 2-year capacity factors greater than 8 percent. These two units primarily fire natural gas but had heat input-based percentages of fuel oil firing that were about 16 percent in at least one of the years from 2019 through 2021 (*i.e.,* slightly above the 15 percent that would qualify them as oil-fired units). The Agency concluded that there are very few continental liquid oil-fired units that are outside the definition of the limited-use liquid oil-fired subcategory. Since the capacity factors of liquid oil-fired EGUs are low, and most combustion by these units relies on fuel (*i.e.,* natural gas) with low metallic HAP emission rates, the Agency did not propose any changes to the total HAP metals, nor to the standards for the individual HAP metals, nor to the HAP metal surrogate fPM emission standards for continental liquid oil-fired EGUs. However, the Agency solicited comment on the appropriateness of including new HAP standards for EGUs in the limited use liquid oil-fired subcategory, as well as the means of demonstrating compliance with the new HAP standards.

Commenters to the 2023 Proposal urged the EPA to retain the current definition of the limited use liquid oil-fired subcategory and not impose new HAP standards on EGUs in this subcategory given that there are already limits on the amount of fuel oil that can be burned. Commenters alleged that changes to the existing HAP standards for EGUs in this subcategory may lead to reliability issues, as these units are crucial to maintaining grid reliability during cold winter spells, other extreme weather events, or when natural gas is curtailed.

One recent extreme weather event impacting the grid was the December 2022 Winter Storm Elliot. Winter Storm Elliott, a bomb cyclone[5] that started to form on December 21, 2022, plunged vast areas of the U.S. into freezing temperatures, inches of snow, and high wind speeds. Due to the extreme winter storm conditions, natural gas production and EGU performance and operation was limited or brought to a halt, resulting in an estimated 1.7 million people losing power from rolling blackouts and loss of generation capacity. According to an October 2023 FERC and NERC report on Winter Storm Elliot[6], there were 90,500 MW in coincident unplanned outages across the U.S. Eastern Interconnection, an unprecedented amount of lost generation.

The extreme cold weather conditions caused by Winter Storm Elliot had the greatest impact on gas facilities due to mechanical issues. According to PJM Interconnection, a regional electric power transmission system operator, gas plants and dual-fuel gas plants accounted for approximately 70 percent of outages, coal comprised 16 percent, and the remainder were oil, nuclear, hydro, wind, and solar. According to the America's Power report on Winter Storm Elliot, the Northeast region averaged approximately 14 GW on December 21 and 22, shown in Figure 5, while 10.6 GW was supplied between December 23 and 26 as plants struggled to operate due to the storm conditions.[7] To compensate for the loss of natural gas generation, ISONE and NYISO, independent electric power transmission system operators in New England and New York, called on oil-fired backup generators and dual-fueled (natural gas and fuel oil) power plants, which supplied an average of 4.3 GW between December 23 and 26, also shown in Figure 6.

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[5] A bomb cyclone is a mid-latitude storm that forms when a cold airmass collides with a warm airmass and undergoes rapid intensification.

[6] "Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliot,' FERC, NERC, and Regional Entity Staff Report. October 2023. *https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott.*

[7] "Operation of the U.S. Power Generation Fleet During Winter Storm Elliot." Energy Ventures Analysis Report for America's Power. February 2023. *https://www.evainc.com/wp-content/uploads/2023/02/2023_02_23-EVA-Winter-Storm-Elliott-Report.pdf.*

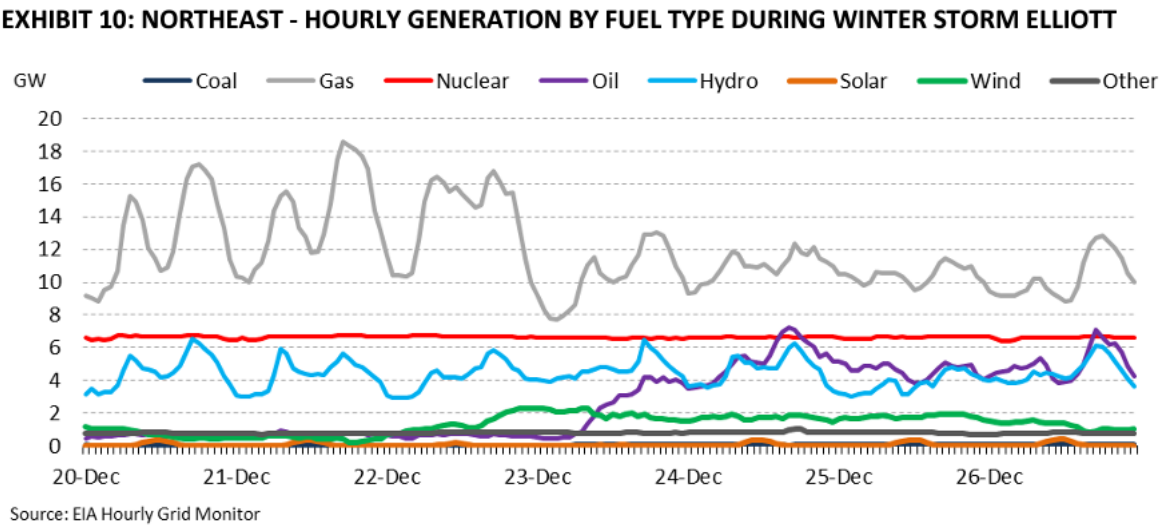

Figure 6. Northeast hourly generation by fuel type during Winter Storm Elliot. Screenshot from America's Power 2023 Report on Winter Storm Elliot.

b. Emission Performance Evaluation of Oil EGUs Operating in New England During Winter Storm Elliot

The rapid increase of oil-fired EGU generation during Winter Storm Elliott is of interest to the EPA due to the possible increase of HAP emissions released into the atmosphere. Emissions from fuel oil combustion depend on the grade and composition of the fuel, type and size of the boiler, the firing and loading practices used, as well as the level of equipment maintenance.[8] Generally, combustion of lighter distillate fuel oils (DFOs) results in significantly lower PM formation, and thus lower non-Hg HAP metals, as compared to that from combustion of heavier residual fuel oils (RFOs). Among RFOs, firing of Nos. 4 and 5 usually produces less PM than firing of heavier No. 6.[9]

The EPA assessed total non-Hg HAP emissions from calendar year 2022 from 11 oil-fired EGUs across New England that were operated to meet the energy demands brought on by Winter Storm Elliott. In addition to Winter Storm Elliot, a nor'easter dumped one to two feet of

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[8] AP 42, Fifth Edition, Volume I, Chapter 1.3: External Combustion Sources. US EPA. 1999, corrected May 2010. *https://www.epa.gov/sites/default/files/2020-09/documents/1.3_fuel_oil_combustion.pdf.*

[9] "Report on Revisions to 5th Edition AP-42, Section 1.3: Fuel Oil Combustion." US EPA. 1998. *https://www.epa.gov/sites/default/files/2020-09/documents/background_document_ap-42_section_1.3_fuel_oil_combustion.pdf.*

snow across the Mid-Atlantic and Northeast on January 28-30, 2022, causing widespread power outages in Massachusetts.[10] The oil-fired EGUs located in Maine are William F Wyman Units 3 and 4 (ORIS id: 1507). The oil-fired EGU located in New Hampshire is Newington Unit 1 (ORIS id: 8002). The oil-fired EGUs located in Connecticut are New Haven Harbor Unit NHB1 (ORIS id: 6156), Montville Units 5 and 6 (ORIS id: 546), and Middletown Units 2, 3, and 4 (ORIS id: 562). The oil-fired EGUs located in Massachusetts are Canal Units 1 and 2 (ORIS id: 1599). All the listed oil-fired EGUs were running during Winter Storm Elliott. Figure 7 shows the location of all 11 oil-fired EGUs.

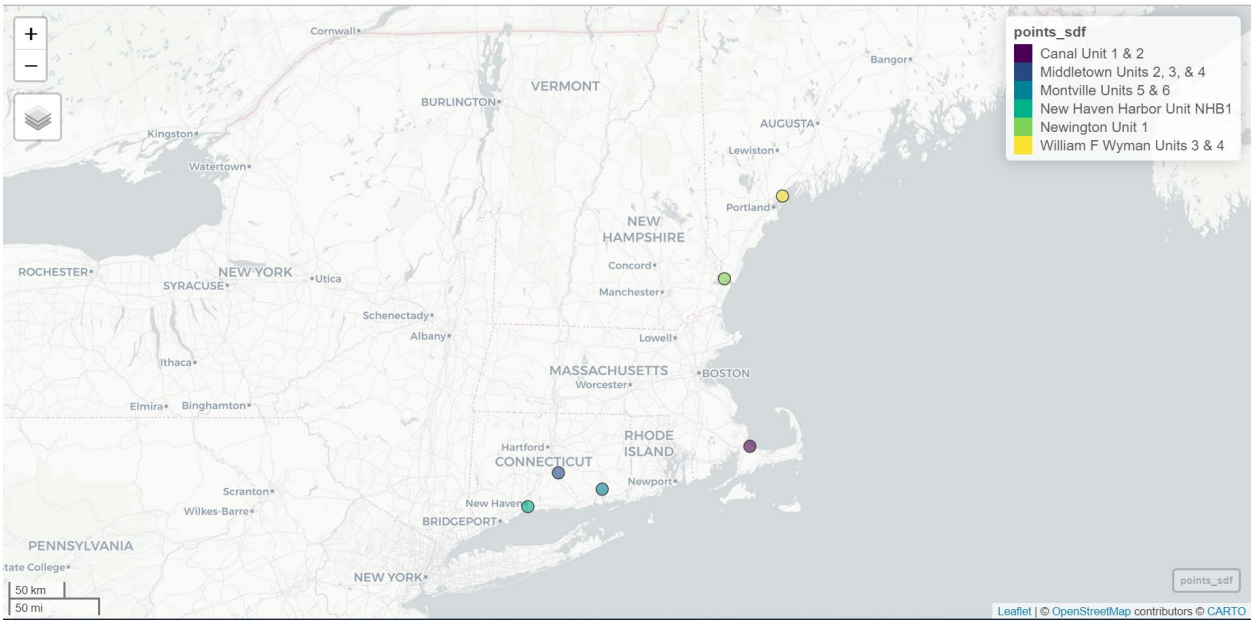

Figure 7. Map showing the location of the 11 oil-fired EGUs in New England during Winter Storm Elliot.

i. Methodology

This section describes the methodology to estimate the 2022 non-Hg metal HAP emissions from the 11 oil-fired EGUs due to burning RFO. Monthly fuel use information for RFO (barrels) was obtained for each EGU from EIA-923 data (https://www.eia.gov/electricity/data/eia923/) and summed to find annual fuel use. AP-42 emission factors for the "external combustion; electric generation; boilers" category burning

[10] "January 2022 National Climate Report." National Oceanic and Atmospheric Administration (NOAA) National Centers for Environmental Information. February 2022. *https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202201.*

RFO were downloaded from WebFIRE (https://cfpub.epa.gov/webfire/SearchEmissionFactor/searchpage.cfm).[11] These emission factors were developed for EGUs without any PM controls. Since the majority of the oil-fired EGUs assessed here have PM controls (*i.e.,* ESPs), we conservatively assumed 96% fPM control for the units with PM controls and applied this reduction to these emission factors. Emission factors were downloaded for the 10 non-Hg HAP metals assessed in the preamble, including arsenic (As), beryllium (Be), cadmium (Cd), cobalt (Co), chromium (Cr), manganese (Mn), nickel (Ni), lead (Pb), antimony (Sb), and selenium (Se). Emission factors for No. 6 fuel oil, in units of lb/1000 gal of fuel oil, were converted into lb/barrels (1000 gal = 23.8095 barrels of oil) of fuel oil. These emission factors had control ratings of C, D, and E. Emissions for each non-Hg HAP metal were calculated using Equation 2:

$$(2)\ X_F \frac{tons}{month} = EF_{x,F} \frac{lb\ non{-}Hg\ metal}{1000\ gallons} \times \frac{1000\ gallons}{23.8095\ barrel} \times Q \frac{barrels}{month} (1 - 0.96) \frac{ton}{2000\ lbs}$$

Where x is the specific non-Hg HAP metal and F is the specific fuel type (barrels of RFO). The total non-Hg HAP metal emissions were calculated by summing the 10 individual metal emissions.

c. Results and Conclusions

Emission estimates from 2022 are compared to results from the modeling of 2017 emissions conducted for the 2020 risk review.[12] The 2020 risk review concluded the residual risks due to emissions of air toxics from the coal- and oil-fired EGU source category are acceptable and that the current standards provide an ample margin of safety to protect human health and prevent an adverse environmental effect. The estimated maximum lifetime individual cancer risk (cancer MIR) posed by the 322 facilities[13] was 9-in-1 million, with nickel compounds from oil fuel sources in Puerto Rico as the largest contributor to the risk. The total estimated cancer incidence from this source category was 0.04 excess cancer cases per year, or one excess case in every 25 years. Approximately 193,000 people were estimated to have cancer risks at or

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[11] Unit-specific emission factors, provided by testing data from previous ICRs, would yield more accurate emission estimates for the unit's configuration. The approach presented here uses average oil-fired EGU emission factors, instead of emission factors specific to individual EGUs.

[12] See "Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2019 Risk and Technology Review Proposed Rule" (Docket ID No. EPA-HQ-OAR-2018-0794-0014).

[13] One facility in Guam is beyond the geographic range of the model used to estimate risks.

above 1-in-1 million from HAP emitted from the facilities in this source category. The estimated maximum chronic noncancer TOSHI for the source category was 0.2 (respiratory), which was driven by emissions of nickel and cobalt from the oil-fired EGUs.

As mentioned in the 2023 Proposal, these EGUs in Puerto Rico do not have emission controls for NOx, PM, or SO_2 and at least 2 have dual fuel capabilities and operated on high levels of natural gas. Limited stack testing done in 2021 and 2022 indicate fPM emission rates ranging from 0.026 to 0.029 lb/MMBtu, just below the emission standard for non-continental liquid oil-fired EGUs of 0.030 lb/MMBtu. Since these EGUs do not have installed control devices for HAP metals (*i.e.,* PM controls), there is no opportunity to improve their performance in the same way the EPA found available for coal-fired EGUs.

The 2017 emissions from the Puerto Rico facilities are listed in Table 5, cumulatively 54,520 lb/year of non-Hg HAP metals. Emissions of total non-Hg HAP metals across the 11 EGUs ranges from 0.0 to 12,483 lb/year, with nickel the dominant contributor. The Puerto Rico Electric Power Authority has recently proposed near-term retirement dates (by 2026) for 10 of the 14 oil-fired EGUs with 2 of the other remaining four boilers burning mostly natural gas. Therefore, emissions from these oil-fired EGUs in Puerto Rico are expected to decrease over the next few years, further reducing risk from HAP exposure.

Table 5. 2017 RFO fuel use (barrels) and HAP metals emissions (lbs/year) from oil-fired power plants in Puerto Rico.

EGU	**2017 RFO (barrels)**	**2017 Cobalt Emissions (lbs/year)**	**2017 Nickel Emissions (lbs/year)**	**2017 Total non-Hg HAP metals Emissions (lbs/year)**
Aguirre Steam Power Plant (AG1)	4,432,735	1783.3	8937.3	12482.8
Aguirre Steam Power Plant (AG2)		0.0	0.0	0.0

Costa Sur Steam Plant (COS3)	1,479,369	474.2	2376.6	3319.4
Costa Sur Steam Plant (COS4)		474.2	2376.6	3319.4
Costa Sur Steam Plant (COS5)		563.3	2823.2	3943.2
Costa Sur Steam Plant (COS6)		305.2	1529.7	2136.5
Palo Seco Steam Power Plant (PS1)	822,599	432.1	2165.7	3024.8
Palo Seco Steam Power Plant (PS2)		0.0	0.0	0.0
Palo Seco Steam Power Plant (PS3)		1624.3	8140.6	11370.0
Palo Seco Steam Power Plant (PS4)		0.0	0.0	0.0
San Juan Steam Power Plant (SJ7)	1,572,662	779.9	3908.4	5458.9
San Juan Steam Power Plant (SJ8)		892.8	4474.5	6249.6

San Juan Steam Power Plant (SJ9)		217.9	1092.0	1525.2
San Juan Steam Power Plant (SJ10)		241.5	1210.1	1690.2

Next, we assess total non-Hg HAP metals emission estimates from the 11 oil-fired EGUs in the Northeast called upon during Winter Storm Elliot. Cumulative total emissions in 2022 were 779 lb/year, 70 times lower than the total emissions from Puerto Rico. All but one of these EGUs employ ESPs for PM controls. ESPs are capable of collection efficiencies greater than 99 percent[14], but we conservatively assume 96 percent collection efficiencies here for units with ESPs. Compared to oil-fired EGUs in Puerto Rico, the Northeast oil-fired EGUs burned less RFO in 2022. In addition, cobalt and nickel emissions from the Northeast EGUs in 2022 were one to four orders of magnitude lower than the 2017 emissions in Puerto Rico. Total 2022 non-Hg HAP metal emissions from the 11 Northeast EGUs ranged from 4.8 to 526.0 lb/year (median=21.7 lb/year), whereas 2017 emissions from the Puerto Rico oil-fired boilers were much higher, ranging from 0 to 12,483 tons/year (median=3,172 lb/year).

Table 6. 2022 RFO fuel use (barrels) and HAP metal emissions (tons/year) from 11 oil-fired EGUs called to operate during Winter Storm Elliot.

Name	**PM Control**	**2022 RFO (barrels)**	**2022 Cobalt Emissions (lb/year)**	**2022 Nickel Emissions (lb/year)**	**2022 Total non-Hg HAP metals Emissions (lb/year)**

[14] Technology Review for the Coal- and Oil-Fired EGU Source Category, July 2018. Document ID EPA-HQ-OAR-2018-0794-0015 at *regulations.gov.*

William Wyman 3 (1507)	ESP	35,633	0.4	5.1	6.2
William Wyman 4 (1507)	ESP	378,758	3.8	53.8	65.9
Newington (8002)	ESP	193,901	2.0	27.5	33.7
New Haven Harbor (6156)	ESP	62,674	0.6	8.9	10.9
Montville 5 (546)	ESP	61,007	0.6	8.7	10.6
Montville 6 (546)	ESP	124,763	1.3	17.7	21.7
Middletown 2 (562)	ESP	98,570	1.0	14.0	17.1
Middletown 3 (562)	ESP	27,582	0.3	3.9	4.8
Middletown 4 (562)	None	120,936	30.6	429.2	526.0
Canal 1 (1599)	ESP	279,988	2.8	39.7	48.7
Canal 2 (1599)	ESP	191,389	1.9	27.2	33.3

As described in the proposal preamble, the annual capacity factors of most continental liquid oil-fired EGUs are low and fall within the limited-use liquid oil-fired subcategory, and therefore are not subject to emission limits. However, if 24-month average heat input due to oil increases such that the unit falls out of the limited-use liquid oil subcategory, the unit would become subject to numeric emission limits. As the majority of the continental liquid-oil fired EGUs employ PM controls, their non-Hg HAP emissions are controlled with efficiencies greater

than 99 percent. In the tables presented above, we find 2022 non-Hg HAP metals emissions from the 11 Northeast oil-fired EGUs are about 70 times lower than 2017 emissions from the oil-fired units in Puerto Rico. The facilities in Puerto Rico were among the facilities with the highest (but acceptable) residual risk in the 2020 residual risk review and the Northeast oil-fired EGUs are better controlled and operate with shorter durations than the oil-fired EGUs in Puerto Rico. As the 2020 risk review found risk from continental and non-continental EGUs acceptable, the EPA did not propose and is not finalizing any changes to the limited-use liquid-oil subcategory. However, as mentioned elsewhere, the Agency has an obligation to conduct technology reviews at least every 8 years and the EPA will continue to evaluate whether any revisions to the emission standards for liquid oil-fired EGUs are warranted.

3. Mercury Limit for Lignite-Fired EGUs

a. Hg Emissions from Coal-fired EGUs

The EPA estimated Hg emissions from coal-fired power plants in 2010 (pre-MATS) to be 29 tons.[15] The EPA estimated that 2021 Hg emissions from coal-fired EGUs were 3 tons (a 90 percent decrease compared to pre-MATS levels).[16] This decline was not entirely due to an increased use of Hg controls as there have also been significant changes in the power sector (*e.g.*, coal plant retirements, increase use of natural gas and renewable energy, *etc*.) in the same time period.

However, as noted in the 2023 Proposal, units burning lignite coal (or units that are permitted to burning lignite) accounted for a disproportionate amount of the total Hg emissions in 2021. As shown in Table 7 below, EGUs permitted to fire lignite, were the top 18 highest Hg emitting EGUs. Overall, in 2021, EGUs permitted to burn lignite were responsible for almost 30 percent of all Hg emitted from coal-fired EGUs, while generating about 7 percent of total megawatt-hours. Lignite accounted for 8 percent of total U.S. coal production in 2021.

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[15] Memorandum: Emissions Overview: Hazardous Air Pollutants in Support of the Final Mercury and Air Toxics Standard. EPA–454/R–11–014. November 2011; Docket ID No. EPA–HQ–OAR– 2009–0234–19914.

[16] 2021 Power Sector Programs Progress Report; available at *https://www3.epa.gov/airmarkets/progress/reports/pdfs/2021_report.pdf* and in the rulemaking docket.

Table 7. Top Hg-emitting EGUs in 2021.

Rank	EGU	2021 Hg Emissions (lb)	State
1	Coal Creek 2	181.8	ND
2	Coal Creek 1	175.6	ND
3	Oak Grove 2	149.8	TX
4	Martin Lake 3	134.4	TX
5	Oak Grove 1	112.7	TX
6	Martin Lake 2	111.0	TX
7	Milton R Young B2	103.1	ND
8	Martin Lake 1	100.7	TX
9	Antelope Valley B2	89.8	ND
10	Coyote B1	79.9	ND
11	H W Pirkey Power Plant 1	71.1	TX
12	Antelope Valley B1	69.6	ND
13	San Miguel SM-1	64.6	TX
14	Sandy Creek Energy Station S01	53.5	TX
15	Limestone LIM2	52.5	TX
16	Milton R Young B1	52.4	ND
17	Comanche 3	50.3	ND
18	Leland Olds 2	50.1	ND
19	James H Miller Jr 3	42.9	AL
20	Labadie 2	42.5	MO

In May 2021, pursuant to authority in section 114 of the CAA, 42 U.S.C. §7414(a), the EPA solicited information related to Hg emissions and Hg control technologies from certain lignite-fired EGUs to inform this CAA section 112(d)(6) technology review. The selected lignite-fired EGUs were asked to provide information on their control configuration for Hg and for other air pollutants (*e.g.*, criteria pollutants such as PM, NO_X, SO_2). Selected information on lignite-fired EGU control configurations that was obtained from the CAA section 114 information request is shown below in Table 8. Additional information on the location, size (capacity), firing configuration, and control configuration of lignite-fired EGUs (including those few that were not included in the CAA section 114 information request) is also included. The additional information was obtained from the EPA's NEEDS database.[17]

[17] National Electric Energy Data System (NEEDS) v621 rev: 10-14-22, available at: *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6*.

Most, but not all, of the EGUs utilized a combination of sorbent injection plus a chemical additive (oxidizing agent) as their primary Hg control strategy. One facility in North Dakota (Antelope Valley) uses a liquid sorbent that is injected to the SO_2 scrubber (spray dryer absorber, SDA). Many of the EGUs used "refined coal." Refined coal is typically produced by mixing proprietary additives to feedstock coal to help capture emissions when the coal is burned. For example, these additives may promote the oxidation of Hg to Hg^{2+} compounds for capture in downstream control equipment (*e.g.*, FGD scrubbers, PM control devices). Several of the facilities noted that use of refined coal as a part of their Hg control strategy was discontinued at the end of 2021 when the refined coal production tax credit (created by the American Jobs Creation Act of 2004) expired. According to a U.S. Government Accountability Office audit report, refined coal producers claimed approximately $8.9 billion in tax credits between 2010 and 2020.

Table 8. Control configurations for lignite-fired EGUs.

Plant Name	State	Capacity (MW)	Firing	Control Configuration	Hg Control Description	Hg Control
Antelope Valley #1	ND	450	tangent	ACI + SDA + FF	Does not use activated carbon as its sorbent, instead **injects a liquid sorbent** to the scrubber. The facility stopped using refined coal in December 2021.	Nalco non-carbon, **non-halogenated liquid sorbent** added to dry scrubber; M-Sorb additive (bromide)
Antelope Valley #2	ND	450	tangent	ACI + SDA + FF		
Coal Creek #1	ND	574	tangent	ACI + ESPC + WFGD	Information not collected in the CAA 114 request	
Coal Creek #2	ND	573	tangent	ACI + ESPC + WFGD		
Coyote	ND	429	cyclone	ACI + SDA + FF	Information not collected in the CAA 114 request	
Leland Olds #1	ND	222	wall	SNCR + ACI + ESPC + WFGD	Activated carbon and oxidizer injections for Hg control	ME2C SEA SF10 Oxidizer and SB24 Activated Carbon
Leland Olds #2	ND	445	cyclone	SNCR + ACI + ESPC + WFGD		
Milton R Young #1	ND	237	cyclone	SNCR + ACI + ESPC + WFGD	Hg controlled by Powdered Activated Carbon Injection plus Oxidizing Agent/Halogen Injection System	DARCO Hg-H **non-halogenated** Powdered Activated Carbon + ADA M-Prove additive
Milton R Young #2	ND	447	cyclone	SNCR + ACI + ESPC + WFGD		
Spiritwood Station	ND	92	FBC	SNCR + ACI + SDA + FF	Hg emissions are controlled by **activated carbon injection system** and a continuous emissions monitoring system (CEMS). The activated carbon injection feed rate is adjusted to maintain emissions below the 4.0 lb/TBtu standard.	Activated Carbon sorbent (not specified)
Limestone #1	TX	831	tangent	SNCR + ACI + ESPC + WFGD	Information not collected in the CAA 114 request	
Limestone #2	TX	858	tangent	SNCR + ACI + ESPC + WFGD		

Major Oak #1	TX	152	FBC	Reagent Injection + SNCR + ACI + FF	Hg is controlled by the **introduction of activated carbon** into each boiler duct directly in front of the baghouse. A **halogen fuel additive is also applied** to the lignite before it enters the day silos.	Cabot DARCO Hg-H **non-Brominated AC** + ADA-ES M-Prove additive
Major Oak #2	TX	153	FBC	Reagent Injection + SNCR + ACI + FF		
Martin Lake #1	TX	800	tangent	ACI + ESPC + WFGD	**Brominated additive injected** into the furnace and **activated carbon injected** upstream of the air heater. In 2020 and 2021 **Refined Coal System** applied an aqueous bromine salt solution to the coal.	ME2C SEA process (**non-Brominated AC** + chemical additive)
Martin Lake #2	TX	805	tangent	ACI + ESPC + WFGD		
Martin Lake #3	TX	805	tangent	ACI + ESPC + WFGD		
Oak Grove #1	TX	855	tangent	SCR + ACI + FF + WFGD	**Brominated activated carbon injected** downstream of the air heater. From 2018 to 2021, the unit was equipped with a **Refined Coal System** for Hg control. This system applied an aqueous bromine salt solution to the coal downstream of the crusher. The refined coal system is no longer in service.	ADA-CS Br-AC
Oak Grove #2	TX	855	wall	SCR + ACI + FF + WFGD		

Red Hills #1	MS	220	FBC	Reagent Injection + ACI + FF	Hg is controlled by **injection of activated carbon** into each boiler duct directly in front of the baghouse. A **fuel additive is also applied to the lignite** before it enters the day silos. The application of fuel additives ended in December 2021.	ADA-CS non-Br AC + ADA-ES M45 liquid additive
Red Hills #2	MS	220	FBC	Reagent Injection + ACI + FF		
San Miguel	TX	391	wall	SNCR + ACI + ESPC + WFGD	Hg is captured using a sorbent enhanced additive (SEA) injected onto the lignite at the pulverizer feeders or directly into the furnace to promote the oxidation and capture of Hg. This is followed by an ACI system located in the boiler exit duct work upstream of the air heaters. The scrubber system also reduces Hg emissions.	ME2C SEA process (non-Br AC + powder-based chemical additive)

Note: ACI = activated carbon injection; SDA = spray dryer absorber (dry scrubber); FF = fabric filter; ESPC = cold side electrostatic precipitator; WFGD = wet flue gas desulfurization scrubber; SNCR = selective non-catalytic reduction (NOx control); reagent injection = sorbent injection into fluidized bed combustor

According to fuel use information supplied to EIA (on form 923), in 2021, 13 of 22 EGUs that were designed to burn lignite utilized refined coal to some extent. However, in 2022, as summarized in Table 9 below, most sources had stopped using refined coal (as mentioned earlier, the federal tax credit for refined coal use expired at the end of 2021). As in 2021, several EGUs located in Texas that are permitted to fire lignite reported use of subbituminous coal in 2021 (ranging from 76 percent up to > 99 percent).

Table 9. 2022 fuel use at lignite-fired EGUs.

Plant Name	Distillate Fuel Oil (%)	Natural Gas (%)	Lignite Coal (%)	Refined Coal (%)	Subbituminous Coal (%)
Antelope Valley 1	0.0%	0.7%	99.3%	0.0%	0.0%
Antelope Valley 2	0.0%	0.7%	99.3%	0.0%	0.0%
Coal Creek 1	0.1%	0.0%	99.9%	0.0%	0.0%
Coal Creek 2	0.1%	0.0%	99.9%	0.0%	0.0%
Coyote 1	0.4%	0.0%	91.2%	0.0%	0.0%
Leland Olds 1	0.2%	0.0%	99.8%	0.0%	0.0%
Leland Olds 2	0.2%	0.0%	99.8%	0.0%	0.0%
Milton R Young 1	0.3%	0.0%	99.7%	0.0%	0.0%
Milton R Young 2	0.3%	0.0%	99.7%	0.0%	0.0%
Spiritwood Station 1	0.0%	5.1%	0.0%	94.9%	0.0%
Limestone 1	0.5%	0.0%	0.0%	0.0%	99.5%
Limestone 2	0.5%	0.0%	0.0%	0.0%	99.5%
Major Oak Power 1	0.0%	0.3%	99.7%	0.0%	0.0%
Major Oak Power 2	0.0%	0.3%	99.7%	0.0%	0.0%
Martin Lake 1	0.1%	0.0%	0.0%	0.0%	99.9%
Martin Lake 2	0.1%	0.0%	0.0%	0.0%	99.9%
Martin Lake 3	0.1%	0.0%	0.0%	0.0%	99.9%
Oak Grove 1	0.0%	0.7%	99.3%	0.0%	0.0%
Oak Grove 2	0.0%	0.7%	99.3%	0.0%	0.0%
Red Hills Generating Facility 1	0.0%	8.2%	91.7%	0.0%	0.0%
Red Hills Generating Facility 2	0.0%	8.2%	91.7%	0.0%	0.0%
San Miguel 1	0.2%	0.0%	99.8%	0.0%	0.0%

b. Review of the Hg Emission Standard for Non-Lignite-Fired EGUs

The final MATS Hg emission limit for EGUs firing non-lignite coals (*i.e.*, bituminous and subbituminous coals) is 1.2 lb Hg/TBtu. To review that emission standard, the EPA

evaluated the 2021 performance of EGUs firing non-lignite coals and found that EGUs firing primarily bituminous coal emitted Hg at an average annual rate of 0.4 lb Hg/TBtu (with a range of roughly 0.2 to 1.2 lb Hg/TBtu). EGUs firing primarily subbituminous coal in 2021 (not including those EGUs that are permitted to burn lignite but burned a significant amount of subbituminous coal) emitted Hg at an average annual rate of 0.6 lb Hg/TBtu (with a range of 0.1 to 1.2 lb/TBtu). This represents a control range of 98 to 79 percent (assuming an average inlet concentration of 5.8 lb/TBtu). The EPA has information on the control configurations of these non-lignite EGUs but does not have detailed information on the type of sorbent injected (*e.g.*, activated carbon or non-carbonaceous; pre-halogenated, *etc.*). The EPA also does not have detailed information on the injection rate of sorbents used for Hg control (if any). Similarly, the EPA does not have information on the type of quantity of chemical additives used (if any). However, the bituminous coal-fired EGUs are already achieving an average annual rate of 0.4 lb/TBtu and the subbituminous coal-fired EGUs are already achieving an average annual rate of 0.6 lb/TBtu and a level of control of ranging 79 to 98 percent. The typical Hg control performance curves for sorbent injection show a leveling off such that increasing the amount of sorbent results in diminishing improvement in Hg control. Based on full-scale demonstration testing of Hg sorbents, this leveling off takes place somewhere greater than 90 percent capture. Without knowing the type of sorbent being injected or the rate of the sorbent injection, it is difficult to determine whether additional emissions can be achieved in a cost-effective manner. For bituminous coal-fired EGUs that do not utilize sorbent injection but rely on co-benefit control from equipment installed for criteria pollutants, it is difficult to determine whether additional Hg emission reduction could be obtained in a cost-effective manner with knowledge of the levels of Hg control achieved in each of the installed controls and, if chemical additives are injected, the type and rate of chemical additive injection. For those reasons, the EPA is not proposing to adjust the Hg emission standard for non-lignite-fired EGUs.

b. Review of the Hg Emission Standard for Lignite-Fired EGUs

The 2012 Final MATS Rule established an Hg emission limit of 4.0 lb/TBtu for EGUs firing lignite. To review that emission standard, the EPA evaluated the 2021 performance of lignite-fired EGUs (including those permitted to burn lignite but that utilized significant amounts of subbituminous coal in 2021) (as shown in Table 11 of the 2023 Technical Memo accompanying the 2023 Proposal). The EPA has updated that information to 2022 emissions and

is shown in Table 10, below). In response to comments received during the public comment period, the EPA updated assumptions regarding the Hg content of the various fuels (which is summarized in the 'Mercury Content of Coals' technical support document available in the rulemaking docket).[18] The table shows a "Hg Inlet" level which reflects the maximum Hg content of the range of feedstock coals that the EPA assumes is available to each of the plants in the Integrated Planning Model, IPM,[19] the estimated control (percentage) needed to meet an emission standard of 4.0 lb Hg/TBtu (the current standard for lignite-fired EGUs) and the estimated control (percentage) to meet an emission standard of 1.2 lb Hg/TBtu (the current standard for non-lignite-fired EGUs). The table also shows the estimated 2021 Hg inlet concentration from actual 2021 fuel usage (as mentioned earlier, some units utilized significant quantities of non-lignite fuel, *e.g.*, subbituminous coal, natural gas, *etc.*) and the 2021 Hg emissions reported to the EPA. The EPA then estimated the apparent level of Hg control for 2021 and the level of control that would been needed to achieve the emission standard applicable to the non-lignite-firing EGUs (1.2 lb Hg/TBtu).

Table 10. Measured Hg emissions and estimated control performance of lignite-fired EGUs in 2022.

Plant Name	**Estimated 2022 Hg Inlet (lb/TBtu)**	**Estimated Hg Control at 4.0 lb/TBtu (%)**	**Estimated Hg Control at 1.2 lb/TBtu (%)**	**2022 Hg Emission Rate (lb/TBtu)**	**Estimated 2022 Hg Control (%)**
Antelope Valley 1	11.2	64.4	89.3	3.03	73.0
Antelope Valley 2	11.2	64.4	89.3	3.00	73.3
Coal Creek 1	9.7	58.7	87.6	3.43	64.6
Coal Creek 2	9.7	58.7	87.6	3.87	60.1
Coyote 1	9.7	58.6	87.6	2.28	76.4
Leland Olds 1	11.3	64.5	89.4	2.34	79.3
Leland Olds 2	11.3	64.5	89.4	3.10	72.5
Milton R Young 1	9.7	58.6	87.6	3.02	68.8

[18] Technical Support Document "*1998 ICR Coal Data Analysis Summary of Findings"* available in the rulemaking docket at EPA-HQ-OAR-2018-0794.
[19] Discussion of how these assumptions were developed for use in the EPA's IPM modeling is available in Chapter 7 of the IPM Documentation.

Milton R Young 2	9.7	58.6	87.6	3.00	69.0
Spiritwood Station 1	9.2	56.5	87.0	2.14	76.8
Limestone 1*	5.8	30.7	79.2	0.78	86.5
Limestone 2*	5.8	30.7	79.2	0.85	85.3
Major Oak Power 1	24.9	84.0	95.2	0.86	96.5
Major Oak Power 2	24.9	84.0	95.2	0.63	97.5
Martin Lake 1*	5.8	31.0	79.3	1.53	73.6
Martin Lake 2*	5.8	31.0	79.3	2.50	56.9
Martin Lake 3*	5.8	31.0	79.3	2.36	59.3
Oak Grove 1	24.8	83.9	95.2	2.53	89.8
Oak Grove 2	24.8	83.9	95.2	2.23	91.0
San Miguel 1	28.9	86.2	95.9	3.03	89.5
Red Hills 1	22.9	82.6	94.8	1.73	92.5
Red Hills 2	22.9	82.6	94.8	1.75	92.4

* These EGUs are permitted to fire lignite but fired subbituminous coal in 2022.

As can be seen in the table, all the North Dakota lignite-fired EGUs are estimated to meet the current standard by achieving a level of control of 70 percent or less. The average reported 2022 Hg emission rate for lignite-fired EGUs located in North Dakota was 2.92 lb/TBtu with an average control of 71.4 percent. The average reported 2022 Hg emission rate for lignite-permitted EGUs located in Texas was 1.73 lb/TBtu (with an average control of 82.6 percent). The average reported 2022 Hg emission rate for lignite-fired EGUs (*i.e.*, excluding those that fired subbituminous coal in 2022) located in Texas was 1.86 lb/TBtu (with an average control of 92.9 percent). The average reported 2022 Hg emission rate for lignite-fired EGUs located in Mississippi was 1.74 lb/TBtu (with an average control of 92.4 percent).

c. Determination of an Achievable Hg Emission Standard for Lignite-Fired EGUs

After reviewing the available literature and other studies and available information, the assumptions made regarding Hg control in the final MATS rule, and the information obtained from compliance reports and the 2022 CAA section 114 information collection, the EPA has determined that there are available controls and methods of operation that will allow lignite-fired EGUs to meet an Hg emission standard of 1.2E-06 lb/MMBtu, which is the same emission standard that is being met by EGUs firing on non-lignite coals

i. Both Lignite and Subbituminous Coal are Low Rank Coals with Low Halogen Content

Coal is classified into four main types, or ranks:[20] anthracite, bituminous, subbituminous, and lignite. The ranking depends on heating value of the coal. Anthracite has the highest heating value of all ranks of coal and is mostly used by the metals industry (it is rarely using for power production). Anthracite accounted for less than 1 percent of the coal mined in the U.S. in 2021. Bituminous coal is also considered a "high rank coal" because of its higher heating value. It is the most abundant rank of domestic coal and accounted for about 45 percent of total U.S. coal production in 2021. Bituminous coal is used to generate electricity and in other industries.

Subbituminous coal and lignite are referred to as "low rank coals". They both have lower heating values than bituminous coal. Subbituminous coal accounted for about 46 percent of total U.S. coal production in 2021, with the vast majority produced in the Powder River Basin (PRB) of Wyoming and Montana. Lignite has the lowest energy content of all coal ranks. Lignite accounted for about 8 percent of total U.S. coal production in 2021. About 56 percent was mined in North Dakota (Fort Union lignite) and about 36 percent was mined in Texas (Gulf Coast lignite).

Chlorine is the most abundant halogen in coal. Bromine may also be present in coal but is typically in much lower concentrations than chlorine.[21] Low-rank coals such as lignite and subbituminous generally have lower chlorine contents than higher rank coals such as bituminous coal.[22]

As mentioned earlier, the halogen content of the coal — especially chlorine — largely influences the oxidation state of Hg in the flue gas stream. As a result, the halogen content of the coal directly influences the ability to capture and contain the Hg before it is emitted into the atmosphere. As explained earlier, 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. This makes control of Hg from

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[20] "Coal Explained, Types of Coal" Energy Information Administration, available at *www.eia.gov/energyexplained/coal* and in the rulemaking docket.
[21] See Figure 5 in the U.S. Geological Survey publication "Mercury and Halogens in Coal—Their Role in Determining Mercury Emissions From Coal Combustion" available at *https://pubs.usgs.gov/fs/2012/3122/pdf/FS2012-3122_Web.pdf*.
[22] *Ibid*.

both subbituminous coal-fired EGUs and lignite-fired EGUs more challenging than the control of Hg from bituminous coal-fired EGUs. However, because control strategies and technologies were developed to introduce halogens to the flue gas stream, EGUs firing subbituminous coals have been able to meet the 1.2 lb/TBtu emission standard in the final MATS rule. 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.

ii. The Hg Content of North Dakota Lignite and PRB Subbituminous Coal are Similar

As explained in the 'Mercury Content of Coal' technical support memorandum[23], the EPA assumed the average Hg content of North Dakota lignite to be 9.7 lb/TBtu and assumed the Hg average content of subbituminous coal (from the Wyoming PRB)- to be 5.8 lb/TBtu. These values are very similar to results from a published study that found the average Hg concentration of North Dakota lignite and PRB subbituminous coals to be very similar. The study found that the North Dakota lignite samples contained an average of 8.5 lb/TBtu and the PRB subbituminous coal samples contained an average of 7.5 lb/TBtu.[24] Despite the similarities in Hg content, halogen content, and alkalinity between North Dakota lignite and PRB subbituminous coal, EGUs firing subbituminous coal in 2021 emitted Hg at an average annual rate of 0.6 lb Hg/TBtu while those firing on North Dakota lignite emitted Hg at an average annual rate of 3.0 lb Hg/TBtu. While the EGUs firing North Dakota lignite at an average emission rate of 3.0 lb Hg/TBtu are complying with the final MATS emission standard of 4.0 lb Hg/TBtu, it is difficult to explain why those units could not meet a similar level of Hg control as that of the EGUs firing PRB subbituminous coal given the similarities between the two fuels – especially the similarities in Hg content, halogen content, and alkalinity. Numerous commenters noted the difference in sulfur content between lignite and Wyoming subbituminous. Sulfur in the coal can lead to formation of sulfur trioxide (SO_3), which is known to negatively affect Hg control using certain

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[23] Technical Support Document "*1998 ICR Coal Data Analysis Summary of Findings"* available in the rulemaking docket at EPA-HQ-OAR-2018-0794.

[24] "Mercury in North Dakota lignite", Katrinak, K. A.; Benson, S.A.; Henke, K. R.; Hassett, D. J.; *Fuel Processing Technology*, 39, 35, 1994.

technologies (especially sorbent injection). But, as explained in the final preamble for this rulemaking, numerous control technology vendors and developers have introduced "sulfur tolerant" sorbents and other control technologies to address this concern. And EGUs firing bituminous coals are much more prone to produce SO_3 than those firing lignite (due to the higher levels of sulfur in most bituminous coals and the presence of SCR systems for NOx control, which are uncommon with lignite-fired EGUs in the U.S.).

The Hg content of Gulf Coast lignite tends to be higher than that of the North Dakota lignite. As explained in the 'Mercury Content of Coal' technical support memorandum[25], the EPA assumed the average Hg content of Texas lignite to be 25.0 lb/TBtu and assumed the average Hg content of Mississippi lignite to be 34.3 lb/TBtu. Despite the higher Hg content, EGUs permitted as lignite-fired had, in 2021, an average Hg emission rate of 2.0 lb/TBtu – below the 2021 average emission rate of EGUs firing North Dakota lignite (at 3.0 lb/TBtu). This is due, in part, because some EGUs in Texas that are permitted as lignite-fired units (and thus subject to the Hg emission standard of 4.0 lb/TBtu) were, in 2021 (and also in 2022 and beyond), firing significant amounts of subbituminous coal. Firing high levels of non-lignite coal (in some cases greater than 99 percent non-lignite coal), while remaining subject to the less stringent Hg emission standard for the subcategory of lignite-fired EGUs seems to fit the scenario that the EPA expressed concern about in the final MATS rule preamble – that "sources to potentially meet the definition by combusting very small amounts of low rank virgin coal [lignite]." *See* 77 FR 9379.

d. Cost of Meeting the Revised Emission Standard

For the final MATS rule, the EPA calculated beyond-the-floor costs for Hg controls by assuming injection of brominated activated carbon at a rate of 3.0 lb/MMacf for units with ESPs and injection rates of 2.0 lb/MMacf for units with baghouses (also known as FF). Yet, in responses to the CAA section 114 information survey, only one facility (Oak Grove) explicitly indicated use of brominated activated carbon. Oak Grove units #1 and #2 (both using FF for PM control) reported use of brominated activated carbon at an average injection rate of less than 0.5 lb/MMacf for operation at capacity factor greater than 70 percent. The Oak Grove units fired, in

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[25] Technical Support Document "*1998 ICR Coal Data Analysis Summary of Findings"* available in the rulemaking docket at EPA-HQ-OAR-2018-0794.

2021, using mostly refined coal.[26] That injection rate is considerably less than the 2.0 lb/MMacf assumed.

From the CAA 114 information survey, the average injection rate reported for non-halogenated sorbents was 2.5 lb/MMacf. As mentioned earlier, most sources utilized a control strategy of sorbent injection coupled with chemical (usually halogenated) additives. In the beyond-the-floor analysis in the final MATS rule, we noted that the results from various demonstration projects suggest that greater than 90 percent Hg control can be achieved at lignite-fired units using brominated activated carbon sorbent at an injection rate of 2.0 lb/MMacf for units with installed FFs for PM control and at an injection rate of 3.0 lb/MMacf for units with installed ESPs for PM control. As shown in Table 10 above, all units (in 2022) would have needed to control their Hg emissions to less than 95 percent to meet an emission standard of 1.2 lb/TBtu. Based on this, we expect that the units could meet the proposed, more stringent, emission standard of 1.2 lb/TBtu by utilizing brominated activated carbon at the injection rates suggested in the beyond-the-floor memorandum from the final MATS rule.

i. Cost-effectiveness for a Model Plant

To determine the cost-effectiveness of that strategy, we calculated the cost-effectiveness (cost per lb of Hg controlled) for a model 800 MW lignite-fired EGU. We calculated the cost of injecting non-brominated activated carbon sorbent at a conservative injection rate of 5.0 lb/MMacf to achieve an emission rate of 1.2 lb/TBtu versus the cost to meet an emission rate of 4.0 lb/TBtu using non-brominated activated carbon sorbent at an emission rate of 2.5 lb/MMacf.

This calculation assumes a model 800 MW EGU with a heat rate of 11,000 Btu/kWh operating at an 80 percent capacity factor fires Gulf Coast lignite with a Hg concentration of 25.0 lb/TBtu. It also assumes that the unit meets a Hg emission standard of 4.0 lb/TBtu using an injection rate of 2.5 lb/MMacf of non-brominated activated carbon at a sorbent cost of $0.80/lb and that the unit can meet a Hg emission standard of 1.2 lb/TBtu using an injection rate of 5.0 lb/MMacf of brominated activated carbon at a sorbent cost of $1.15/lb.

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[26] EIA form 923 does not specify the rank of coal that is “refined.” For this technology review, the EPA has assumed that facilities reporting the use of refined coal have utilized “refined lignite.”

$$800\ MW\ x\ \left(\frac{8{,}760\ hr}{year}\right) x(80\%\ CF) = 5{,}606{,}400\ \frac{MWh}{year}$$

$$5{,}606{,}400\ \frac{MWh}{year}\ x\ 11\ \frac{mmBtu}{MWh}\ = 61{,}670{,}400\ \frac{mmBtu}{year} = 8{,}880\ \frac{mmBtu}{hr}$$

$$61{,}670{,}400\ \frac{mmBtu}{year}\ x\ \left(25.0\ x\ 10^{6}\ \frac{lb\ Hg}{mmBtu}\right) = 1{,}542\ \frac{lb\ Hg\ in}{year}$$

$$At\ an\ emission\ standard\ of\ 4.0\ \frac{lb\ Hg}{TBtu} = 247\ \frac{lb\ Hg}{year}\ emitted\ (84\%\ control)$$

$$2.5\ \frac{lb\ sorbent}{MMacf} x\ 9{,}860\ \frac{scf}{mmBtu} x\ \left(\frac{785\ R}{520\ R}\right)\ x\ (1 - 0.06)\ x\ \left(\frac{20.9 - 7.0}{20.9}\right)\ x\ 8{,}880\ \frac{mmBtu}{hr}\ x\ \frac{1\ MMacf}{1{,}000{,}000\ acf} =\ 463\ \frac{lb\ sorbent}{hr}$$

$$Sorbent\ cost =\ \frac{463\ lb}{hr}\ x\ \frac{8{,}760\ hr}{year}\ x\ 80\%\ CF\ x\ \frac{\$0.80}{lb} = \$2{,}594{,}832\ per\ year$$

$$Cost\ effectiveness = \left(\frac{\$2{,}594{,}832}{(1{,}542 - 247)\ lb\ Hg\ removed}\right) = \frac{\$2{,}004}{lb\ Hg\ removed}$$

$$At\ an\ emission\ standard\ of\ 1.2\ \frac{lb\ Hg}{TBtu} = 95\ \frac{lb\ Hg}{year}\ emitted\ (95\%\ control)$$

$$5.0\ \frac{lb\ sorbent}{MMacf} x\ 9{,}860\ \frac{scf}{mmBtu} x\ \left(\frac{785\ R}{520\ R}\right)\ x\ (1 - 0.06)\ x\ \left(\frac{20.9 - 7.0}{20.9}\right)\ x\ 8{,}880\ \frac{mmBtu}{hr}\ x\ \frac{1\ MMacf}{1{,}000{,}000\ acf} =\ 926\ \frac{lb\ sorbent}{hr}$$

$$Sorbent\ cost =\ \frac{926\ lb}{hr}\ x\ \frac{8760\ hr}{year}\ x\ 80\%\ CF\ x\ \frac{\$1.15}{lb} = \$7{,}460{,}143\ per\ year$$

$$Cost\ effectiveness = \left(\frac{\$7{,}460{,}143}{(1{,}542 - 95)\ lb\ Hg\ removed}\right) = \frac{\$5{,}083}{lb\ Hg\ removed}$$

$$Incremental\ cost\ effectiveness = \frac{(\$7{,}460{,}143 - \$2{,}594{,}832)}{(1{,}468 -\ 1{,}295)\ lb\ Hg\ controlled}$$

$$= \$28{,}176\ per\ lb\ Hg\ removed$$

This is a conservative value as it is unlikely that sources will need to inject brominated activated carbon sorbent at rates as high as 5.0 lb/MMacf (the Oak Grove units were injecting less than 0.5 lb/MMacf) and is consistent with the cost-effectiveness that the EPA has found to be acceptable in previous rulemakings.

4. Transparency of PM CEMS

Continuous monitoring of fPM required in this rule provides several unquantifiable benefits, including greater certainty, accuracy, transparency, and granularity in fPM emissions information as compared to the intermittent stack testing that most affected sources employ. Here, we show fPM emissions for EGUs for which both intermittent stack testing and continuous monitoring data are available, supporting the discussion provided in section IV.D.2 of the preamble.

Hourly PM CEMS data were filtered to remove fPM data during periods of startup and shutdown and offline/invalid periods if indicated by the facility in the hourly PM CEMS file. If these periods were not indicated, hourly operational data from the EPA's Clean Air Markets Program Division (CAMPD)[27] were used to flag and remove hours where the EGU was not running the entire hour, where the hourly heat input was zero, and where the gross load was low to remove periods of startup and shutdown. The 30-boiler operating day average, which is required for demonstrating compliance with the fPM limit using PM CEMS, was calculated by dividing the sum of quality-assured hourly emissions obtained over the hours of operation in 30 days by the number of hourly rate values collected over 30 days of operation, as shown in equation 8 in 40 CFR 63.10021(b).

Hourly heat input data were downloaded from EPA's CAMPD website, included in Attachment 3 to this memorandum's docket entry, to calculate annual emissions from stack testing and hourly PM CEMS data. Emissions estimates for a fPM limit of 0.010 lb/MMBtu and stack testing were calculated by multiplying the specific fPM rate (lb/MMBtu) by the heat input

[27] *campd.epa.gov*.

(MMBtu) and converted into tons. All hourly PM CEMS data were used to calculate the annual emissions (*i.e.,* did not remove data flags indicating periods of startup and shutdown)[28].

a. Case Study 1

The first case study focuses on a 1,200 MW facility with three coal-fired EGUs located in the Midwest. Units 1A and 1B are both 585 MW bituminous-fired EGUs, with cold-side ESPs for PM control. Unit 1C is a 620 MW bituminous-fired EGU, with a hot-side ESP for PM control. Hourly average PM CEMS data for Units 1A and 1B were submitted to EPA as part of obligations under a consent decree and not used for compliance demonstration purposes and are available in the docket as an attachment to this technical memorandum. Units 1A and 1B have achieved LEE status for fPM and are currently required to demonstrate compliance with an emission standard of 0.015 lb/MMBtu using intermittent stack testing every three years. Submittal of hourly fPM CEMS data for Unit 1C was not required by the consent decree.

Figure 8 shows the PM CEMS data below 0.110 lb/MMBtu available for Units 1A and 1B from 2019 to mid-2023. During the reporting period, hourly PM CEMS data for Unit 1A (N=40,060) range from near-zero to 1.33 lb/MMBtu, with average and median values of 0.0028 and 0.0020 lb/MMBtu, respectively. For Unit 1B, the hourly PM CEMS data range from near-zero to 0.070 lb/MMBtu, with average and median values of 0.0023 and 0.0020 lb/MMBtu, respectively. The 25th and 75th percentiles of the hourly PM CEMS fPM rates for both Units 1A and 1B are 0.0010 and 0.0030 lb/MMBtu, respectively. The highest daily averages, which are less variable than the hourly data, are 0.104 lb/MMBtu for Unit 1A and 0.033 lb/MMBtu for Unit 1B.

[28] Note this case was developed to show EGU fPM variability of PM CEMS values over a year, not to demonstrate compliance with the MATS fPM emission limit.

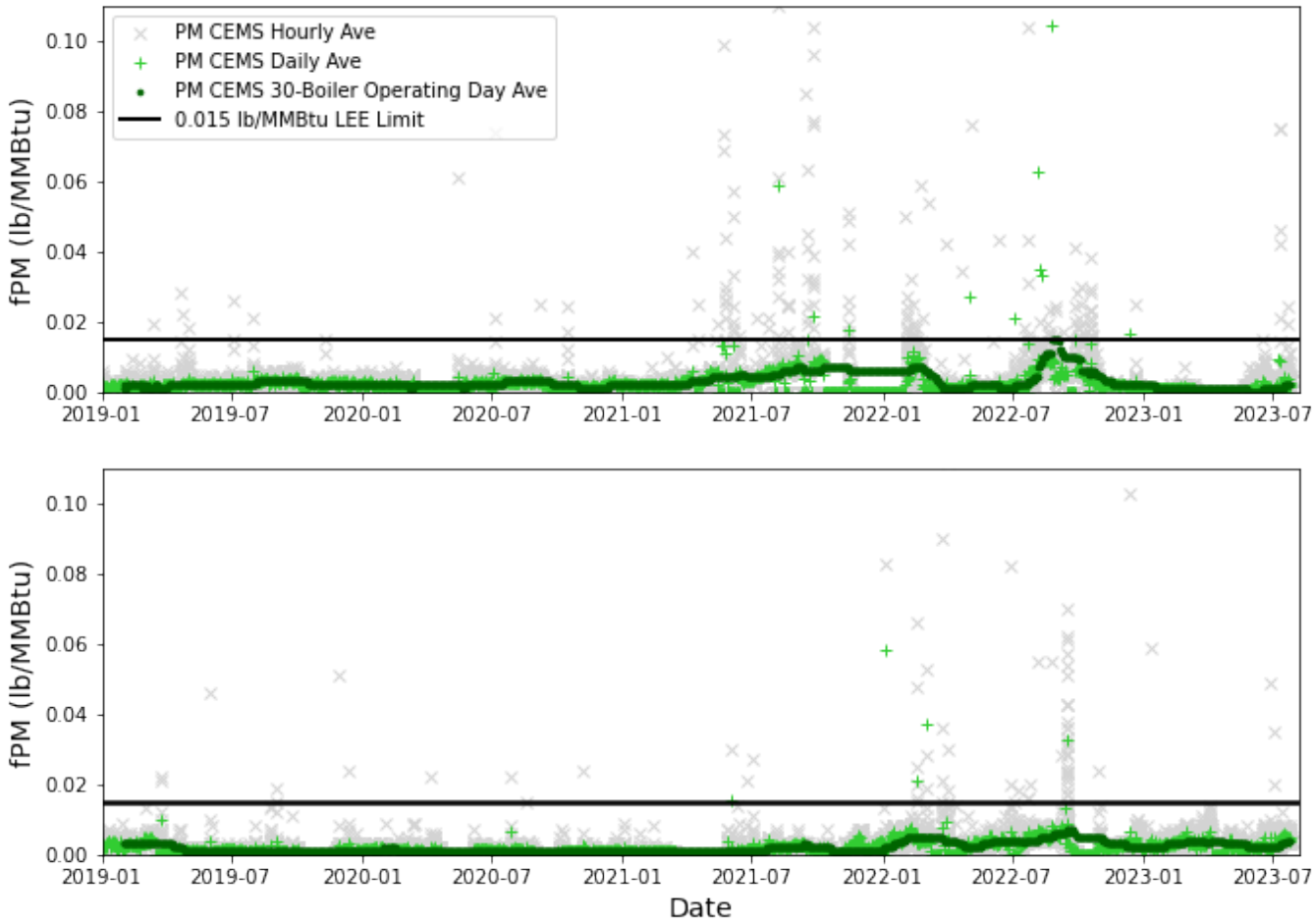

Figure 8. PM CEMS data for Units 1A (top) and 1B (bottom) between 2019 and mid-2023 below 0.11 lb/MMBtu.

Figure 9 highlights the time period from the last two LEE intermittent stack testing reports submitted by the unit, showing 30-boiler operating day averages from mid-September 2019 to January 2023. The compliance reports provide September 18, 2019, stack test averages for Units 1A and 1B of 0.0079 and 0.0068 lb/MMBtu, respectively. Over the subsequent 36 months over which these units were not subject to any further compliance stack testing, continuous monitoring demonstrates that the 30-boiler operating day average fPM emission rates were two to six times lower than the rate measured during the LEE stack test. Next, in the most recent LEE compliance report, Units 1A and 1B measured a February 25, 2021, intermittent stack test average emission rate of 0.0017 and 0.0010 lb/MMBtu, respectively. After this LEE test in February 2021, continuous monitoring shows the 30-boiler operating day average fPM emission rates increased substantially from the emission rates measured during the 2021 stack

test. At one point in mid-2022, the continuously monitored 30-boiler operating day average fPM emissions rate for Unit 1A was about nine times higher than the 2021 intermittent stack test average, reaching the fPM LEE limit of 0.015 lb/MMBtu. Upon reaching the 0.015 lb/MMBtu fPM LEE limit, the 30-boiler operating day average for Unit 1A decreased sharply and stabilized again toward the end of 2022 near the February 2021 LEE test average value. This case study illustrates the potential benefit of having continuous, quality-assured PM CEMS data that inform owners and operators that their fPM rates are rising, prompting corrective action. In the absence of this continuous information, EGUs have the potential to emit above their applicable emission standards for periods of months or years between intermittent stack tests.

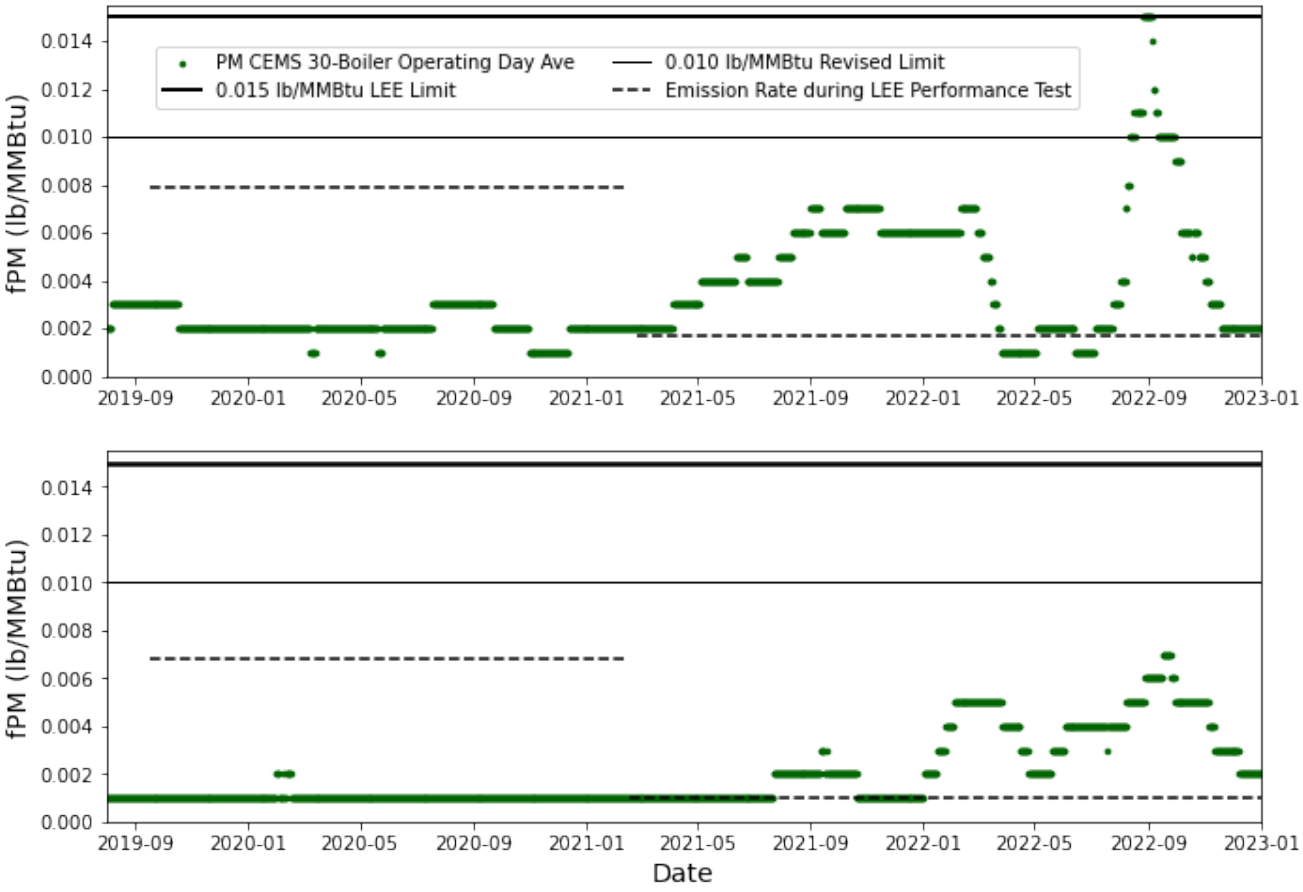

Figure 9. PM CEMS 30-boiler operating day averages and LEE stack test averages for Units 1A (top) and 1B (bottom) from September 2019 to the end of 2022.

In addition to providing EGU owner/operators with the ability to quickly detect, identify, and correct potential control device or operational problems, CEMS provide greater accuracy and transparency regarding the actual emissions from the units, which provides benefits to regulators as well as other stakeholders such as communities near these sources. To illustrate this point, EPA performed a comparison of the differences in 2022 annual fPM emissions for Units 1A and 1B estimated using the rate measured during the most recent stack test with 2022 annual fPM emissions based on hourly fPM rates recorded by the PM CEMS. The comparison shows that the use of the fPM rate measured during the stack test to determine annual emissions significantly underestimates the actual annual fPM emissions. Table 11 summarizes the estimated annual emissions based on stack testing and the actual emissions measured using the PM CEMS. For Unit 1A, 2022 emissions based on PM CEMS are approximately 2.5 times higher than emission estimates based on the average emission rate during the most recent stack test, whereas for Unit 1B, the emissions based on continually measured data from PM CEMS are approximately 4 times higher than emission estimates based on the average emission rate during the most recent stack The results also show annual emissions estimates using both stack testing and PM CEMS for both units are well below the annual emissions estimate assuming a constant fPM emission rate of 0.010 lb/MMBtu (184 and 159 tons/year for Units 1A and 1B, respectively). If this unit, using intermittent stack testing for compliance, was aiming to meet a fPM limit of 0.010 lb/MMBtu,[29] these emission results would indicate compliance. However, revisions under MATS will require continuous compliance using PM CEMS on a 30-boiler operating day average, and Figure 8 illustrates that there were 25 days with averages above the revised fPM limit of 0.010 lb/MMBtu for Unit 1A, ranging from 0.011 to 0.015 lb/MMBtu. Therefore, while the annual emissions estimates from stack testing and PM CEMS both indicate compliance with the revised fPM limit of 0.010 lb/MMBtu on an annual basis, only utilizing PM CEMS for compliance would show that the EGU approached and exceeded 0.010 lb/MMBtu for 25 days during the time period reviewed. Lastly, continuous measurements determine accurate real-world emissions, especially when compared to emission factors, and are usually the

[29] Note that this is for demonstration purposes only, as this unit was not trying to meet this lower fPM limit, and was not subject to a fPM limit of 0.010 lb/MMBtu.

preferred way to establish emissions.[30] More accurate emission inventories are beneficial when determining permit classifications and fees, performing air quality modeling for criteria pollutant attainment and maintenance plans, and monitoring progress and trends of emissions. Additionally, the recent Air Emissions Reporting Requirements (AERR) proposal (88 FR 54118) specified that owners or operators should estimate emissions with the best available data for reporting to EPA for the National Emissions Inventory. The proposal cited CEMS-based emissions as the best to use and noted past EPA guidance in AP-42 that indicated this preference. By requiring CEMS, this rule will additionally provide better emissions data, which in turn provides better data for States to use for State Implementation Plans and the many other benefits of improved emissions data cited in the AERR proposal.

Table 11. 2022 fPM emissions calculations for Case Study 1.

	Unit 1A 2022 fPM Emissions (tons/year)	Unit 1B 2022 fPM Emissions (tons/year)
2022 Annual Emissions Calculated from Hourly PM CEMS Data	77	67
2022 Annual Emissions Calculated from Most Recent Stack Test (current compliance method)	31	16

b. Case Study 2

Case Study 2 reviews data from 2018 to 2022 at a 1,600 MW facility with 2 coal-fired EGUs located in the Midwest. Units 2A and 2B are both 815 MW bituminous-fired EGUs, with cold-side ESPs and wet ESPs for PM control. Units 2A and 2B use PM CEMS for compliance with an emission standard of 0.030 lb/MMBtu on a 30-boiler operating day rolling average basis. The EPA received the hourly PM CEMS data with QA flags from a CAA section 114 request submitted to Region 5 and compared them to results from the facility's PM CEMS relative

[30] "General Information for Emission Inventories." North Carolina Department of Environmental Quality. Accessed on April 5, 2024. *https://www.deq.nc.gov/about/divisions/air-quality/outreach-education-engagement/air-quality-science-and-data/emission-inventories/general-information-emission-inventories*.

response audits (RRAs) submitted to WebFIRE as the facility does not undergo quarterly stack testing. The RRA results during the time period evaluated here are 0.0050 lb/MMBtu (February 2018) and 0.0079 lb/MMBtu (March 2019) for Unit 2A and 0.0027 lb/MMBtu (February 2018) and 0.0069 lb/MMBtu (March 2019) for Unit 2B.

As shown in Figure 10, the highly variable PM CEMS hourly and daily average data from Units 2A and 2B are smoothed out in the 30-boiler operating day averages used for compliance. Hourly PM CEMS data for Unit 2A range from near-zero to 0.026 lb/MMBtu, with mean and median values both about 0.005 lb/MMBtu. Similarly, the hourly PM CEMS data for Unit 2B range from near-zero to 0.039 lb/MMBtu, with mean and median values also about 0.005 lb/MMBtu. Over the 2018 to 2021 time period, the 30-boiler operating day averages from Units 2A and 2B were well below the 0.030 lb/MMBtu limit (with compliance margins of approximately 80 percent on average) and met but did not exceed the revised 0.010 lb/MMBtu limit (with compliance margins of approximately 50 percent on average). Comparisons to the 2 RRAs conducted over this time period indicate emissions measured by PM CEMS were, at their peak, about 2 to 3 times higher than the RRA results in 2018 to, at their trough, about 3 to 4 times lower than the RRA results from 2019 to 2021. This case study illustrates how infrequent stack testing, unlike PM CEMS, cannot reflect EGU operational variability. Infrequent stack testing occurs over normal operating conditions, generally between 90 and 110 percent of the EGU's load.[31] However, as shown in the data, actual operating load—and accompanying emissions—vary from around 60 to 110 percent load. Stack testing is incapable of capturing emissions between the quarterly or triannual period between retests, mainly because no stack testing measurements are made during those periods. On the other hand, PM CEMS captures, collects, and calculates actual emissions at least every 15 minutes, so actual EGU operational variability is captured. This case study highlights the potential benefits of continuous, quality-

[31] See 40 CFR 63.10007(a)(2) on performance testing demonstration requirements. "If you conduct performance testing with methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (*e.g.*, quarterly) performance test. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operating conditions during each test run."

assured PM CEMS data over a range of operating conditions, including startup and shutdown periods.[32]

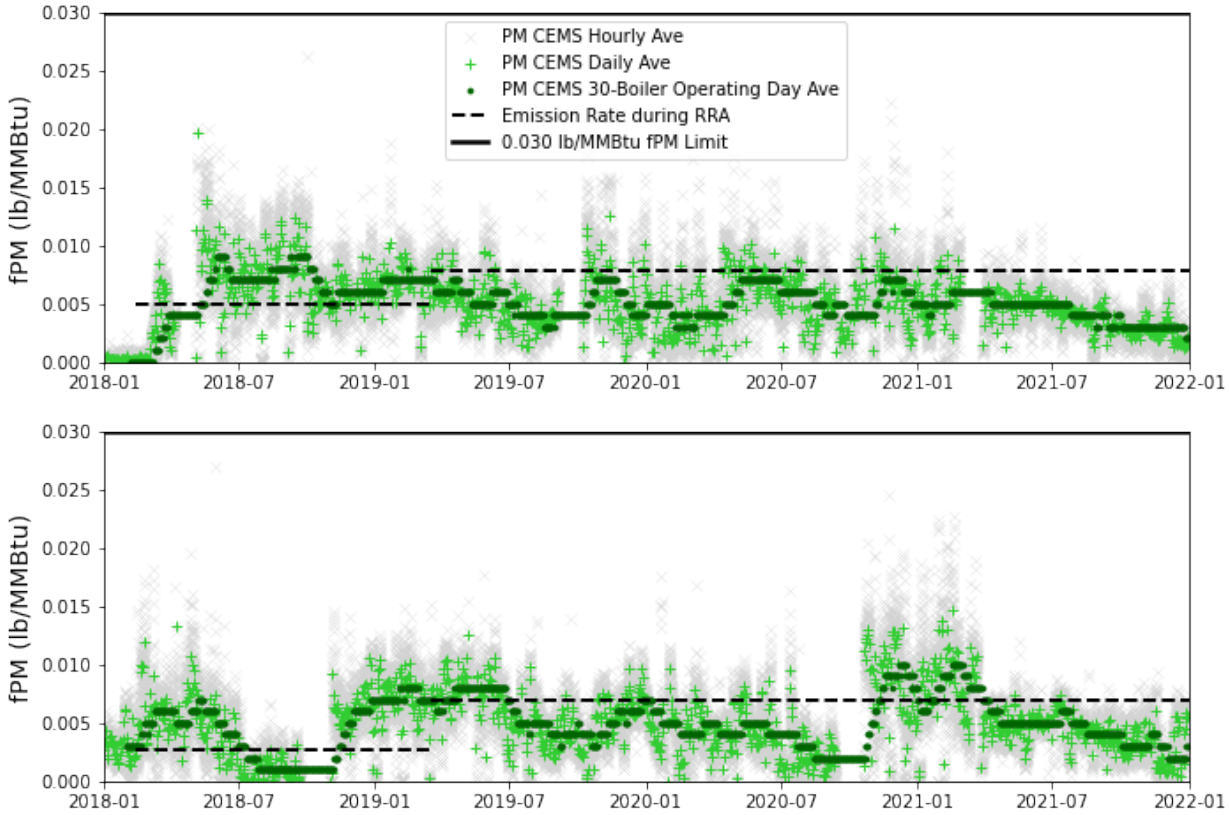

Figure 10. PM CEMS data and comparison to results from the facility's RRAs for Units 2A (top) and 2B (bottom) between 2018 and 2022.

Annual calculated emissions for 2018 and 2021 for Units 2A and 2B are shown in Table 12. Since this facility does not use stack testing for compliance demonstration purposes, we use results from the most recent RRA as a proxy to determine stack testing emissions. Similar to Case Study 1, the results show emissions calculations using both RRAs and PM CEMS are well below the annual emissions calculation assuming a constant fPM emission rate of 0.010 lb/MMBtu (327 and 328 tons/year for Units 2A and 318 and 335 tons/year for Unit 2B, for 2018 and 2021, respectively). Unlike Case Study 1, however, data from PM CEMS for Units 2A and

[32] See 40 CFR 63.10007(a)(1) on PM CEMS demonstration requirements. "Emission rates determined during startup periods and shutdown periods (as defined in 40 CRF part 63.10042) are not to be included in the compliance determinations."

2B illustrate the annual emissions variability between compliance demonstration options. For example, 2018 PM CEMS emissions for Unit 2B are about 1.5 times higher than what emissions estimated using stack testing values from the corresponding RRA, while 2021 PM CEMS emissions for this unit are about 1.3 times lower than stack testing indicates. As continuous measurements provide an accurate accounting of emissions, as opposed to the estimates that can be calculated from RRA stack testing values, this case study highlights that if this facility relied on stack testing alone for its compliance demonstration with the fPM standard, emissions could be overestimated or underestimated. The increased transparency provided by PM CEMS is of critical importance for EGU owners and operators, regulators, and nearby communities.

Table 12. 2018 and 2021 fPM emission calculations for Case Study 2.

	Unit 2A		Unit 2B	
	2018 Annual Emissions (tons/year)	2021 Annual Emissions (tons/year)	2018 Annual Emissions (tons/year)	2021 Annual Emissions (tons/year)
Annual Emissions Calculated from Hourly PM CEMS Data	181	134	129	172
Annual Emissions Calculated from Most Recent RRA	163	259	86	231