Andover Technology Partners 978-683-9599
Consulting to the Air Pollution Control Industry

ASSESSMENT OF POTENTIAL REVISIONS TO THE MERCURY AND AIR TOXICS STANDARDS

C-23-CAELP_1

to:

Center for Applied Environmental Law and Policy (CAELP)

June 15, 2023

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Contents

I. Executive Summary

This technical report evaluates the feasibility and costs of achieving the emission limits in US EPA's April 24, 2023, proposal to revise the Mercury and Air Toxics Standards (MATS) for coal- and oil-fired electric utility steam generating units, as wells as the feasibility and costs of complying with lower emission limits.[1] This report focusses on coal generating units. The following are proposed changes to the MATS rule:

- Lowering the filterable particulate matter ("fPM" or "PM") emission rate used to demonstrate compliance with the non-mercury metal standards to 0.010 lb/MMBtu.[2]
- Requiring use of PM continuous emission monitoring systems (CEMS) on all units.
- Lowering the mercury (Hg) standard for units combusting lignite (virgin low-rank coals) to 1.2 lb/TBtu, the current limit for units combusting non-virgin low-rank coals.

EPA also sought comment on lower fPM emission standards and on developments in control techniques that could warrant strengthening the limits on Hg emissions from units combusting non-lignite coals and on acid gas emissions.

In this report, Andover Technology Partners (ATP) examines the potential for compliance with lower PM, Hg, and hydrochloric acid (HCl) emission standards than in the proposed rule.

ATP previously examined the potential for reduction of emissions of hazardous air pollutants from coal-fired electric generating units (EGUs) in three reports:[3]

- Staudt, J., *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants – Addendum, Analysis of the Cost of Complying with Lower Hg Emissions Levels*, for Center for Applied Environmental Law and Policy (CAELP)**,** January 5, 2023
- Staudt, J. *Opportunities for Reducing Acid Gas Emissions on Coal-Fired Power Plants*, for Center for Applied Environmental Law and Policy (CAELP), April 5, 2022
- Staudt, J., *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants, for* Center for Applied Environmental Law and Policy (CAELP)**,** August 19, 2021

The analysis in these reports determined that there have been significant developments in PM, Hg, and acid gas control technologies regarding cost or performance since the 2012 MATS

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[1] Federal Register / Vol. 88, No. 78 / Monday, April 24, 2023, pg. 24,857.

[2] As a matter of clarification, "PM" or "fPM" emissions refer to the non-mercury metal standards. Currently, compliance with the non-mercury metal standards can be demonstrated through measurements of specific non-mercury metals or through compliance with a filterable PM (fPM) emission standard. Most facilities have chosen to demonstrate compliance through the fPM standard, which was determined to be 0.030 lb/MMBtu in the 2012 MATS rule.

[3] These are available at: https://www.andovertechnology.com/articles-archive/

rule. The developments described in these reports suggest that lower emissions standards are achievable. These reports also presented cost estimates of complying with lower emission limits.

A 2015 analysis by ATP demonstrated that US EPA overestimated the cost of the 2012 MATS rule at the time it was promulgated, in large part by overestimating the need for fabric filters (FFs), also known as baghouses (BHs). That 2015 study further determined that EPA also did not account for improvements in control technologies that were deployed while industry sought out methods to meet emission standards at minimal cost.[4] Advances in control technologies included advances in PM, Hg, and acid-gas controls that were not accounted for in EPA's analysis for the 2012 MATS rule.

A summary of the results of this analysis is as follows:

A. PM Emissions

ATP finds that electrostatic precipitator (ESP) upgrades are capable of far greater emission reductions than assumed by EPA in developing the proposed rule. This has significant implications for the cost of reducing emissions to below 0.010 lb/MMBtu. As will be described in more detail in the body of this report, ATP's cost methodology assumes that all coal units continue to operate. When comparing EPA's cost estimates to those of ATP, it is important to note that differences are the result of differences in modeling assumptions, such as differences in the costs of retrofitting or upgrading control technology, in the emission reductions associated with such retrofits or upgrades, and in the degree of emission reduction necessary to comply with a standard.

ATP's estimate of fleetwide cost of compliance is somewhat higher than that of EPA for emission standards of 0.015 lb/MMBtu and 0.010 lb/MMBtu. This is due to ATP assuming an additional compliance margin that results in more units incorporating improvements to their fPM equipment in ATP's estimate.[5] ATP has determined that the cost to comply with an emission standard of 0.006 lb/MMBtu on a fleetwide basis is significantly less than the cost estimated by EPA (see Figure ES-1). This is due to the assumptions EPA made regarding the potential emission reductions from ESP upgrades, which result in a much higher estimate of baghouse retrofits in EPA's analysis for an emission rate of 0.006 lb/MMBtu: 11 units for ATP versus 39 for EPA (see Figure ES-2). EPA did not examine emission standards lower than 0.006 lb/MMBtu. ATP also determined that lower emission standards of 0.0024 lb/MMBtu and 0.0015 lb/MMBtu would result in significantly higher costs than the less stringent emission standards as a result of the need for greater numbers of baghouses.

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[4] Staudt, J., Declaration before United States Court of Appeals for the District of Columbia Circuit, September 23, 2015, available at: https://www.andovertechnology.com/articles-archive/.

[5] For emission rates of 0.015 and 0.010 lb/MMBtu, when ATP does not assume a compliance margin, ATP estimates total costs that are much closer to those estimated by EPA.

Figure ES-1. Fleetwide estimated annualized costs ($2019) for compliance with different fPM emission standards/BH default rate, ATP versus EPA[6]

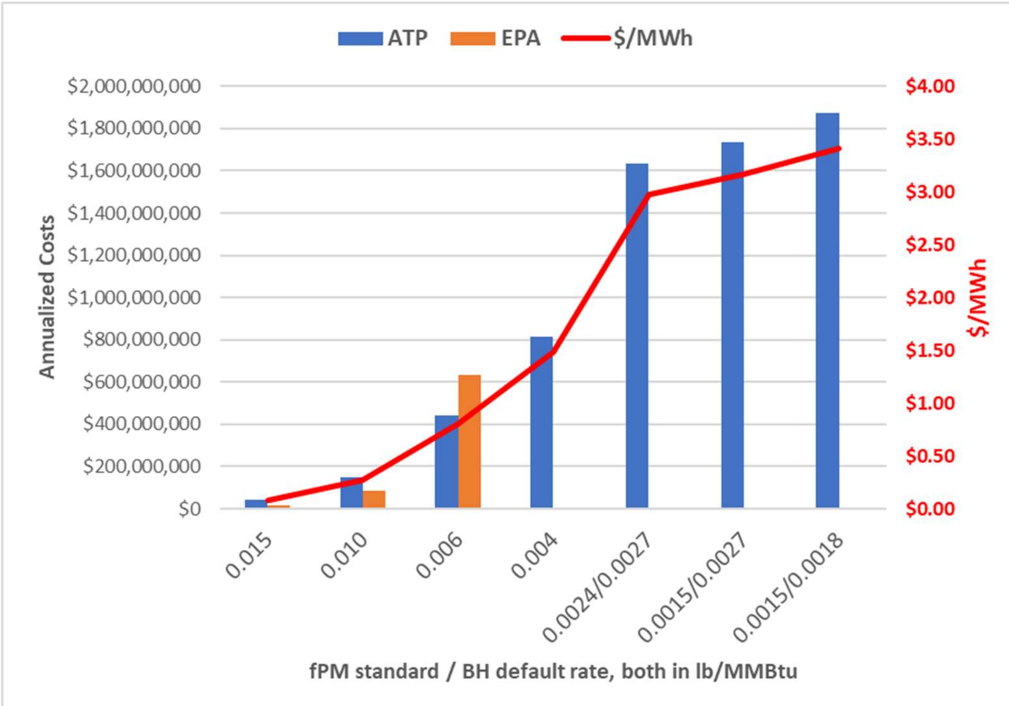
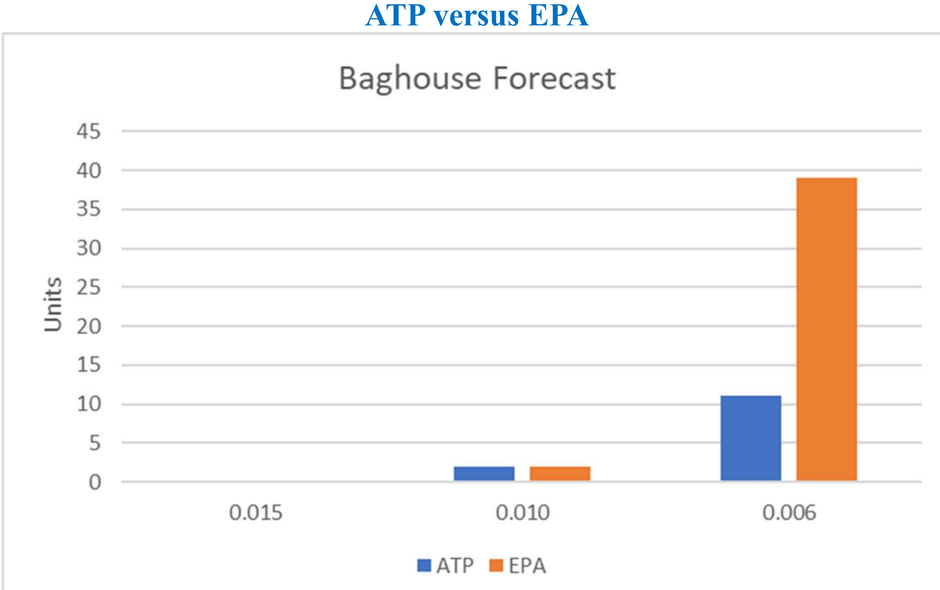


Figure ES-2. Comparison of new baghouse forecasts for different fPM emission standards, ATP versus EPA



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[6] For lower fPM standards, the BH default rate is a conservative assumption that is designed to account for the fact that as the emission standard is lowered, ESP upgrades are likely to be less effective in reducing fPM emissions. BH default rate is a threshold beginning emission rate above which it is assumed that an ESP upgrade will not be sufficient to reach the limit even if the percent reduction is within the range for an ESP upgrade. Therefore, a lower BH default rate will increase the number of BH installations.

1. PM CEMS

ATP has determined that PM CEMS are available and are being used to report emissions to well below 0.010 lb/MMBtu. The issue of developing calibration curves with comparative Method 5 measurement, which is the primary concern expressed by EPA, may be addressed by longer Method 5 sampling for low levels or through other means discussed in the body of this report.

B. Hg Emissions

ATP finds that the proposed Hg limit can easily be complied with primarily though increases in activated carbon injection (ACI) rates at those lignite units that require greater Hg emission capture. This is consistent with EPA's analysis. Fleetwide cost estimates are presented.

ATP also has determined that lower Hg emission limits are achievable for both lignite (low rank) and non-lignite (not low rank) coal units. [7] ATP examined Hg emission limits of 1.2 and 0.50 lb/TBtu for lignite units and 0.50 and 0.15 lb/TBtu for non-lignite units. Because of the role that baghouses play in impacting both Hg emissions removal and the performance of ACI, the costs of complying with these Hg emission limits are examined assuming prior compliance with three different fPM emission standards: 0.006 lb/MMBtu, 0.004 lb/MMBtu, and 0.0024 lb/MMBtu. ATP calculated the total fleetwide cost, cost effectiveness ($/lb Hg reduced), and the impact to the cost of generation ($/MWhr) for both lignite and non-lignite units. More-stringent fPM standards result in lower Hg control costs for any given Hg level because of the impact of baghouses in reducing the cost to control Hg.

The analysis shows that Hg emissions from non-lignite units can be reduced at similar costs (measured by impact to the cost of generation) as can emissions from lignite units. For example, with an fPM emission limit of 0.006 lb/MMBtu and a non-lignite Hg limit of 0.5 lb/TBtu, the impact to the cost of generation is estimated to be $0.10/MWhr. For lignite units complying with the proposed Hg standard of 1.2 lb/TBtu the incremental impact to generation is $0.11/MWhr - $0.13/MWhr, depending upon whether the fPM limit is 0.006 lb/MMBtu or 0.010 lb/MMBtu, respectively. Lower lignite Hg limits entail higher costs. For lignite units, a Hg limit of 0.50 lb/TBtu is estimated to cost $1.33/MWhr with an fPM limit of 0.006 lb/MMBtu and $0.24 lb/MWhr with an fPM limit of 0.0024 lb/MMBtu. For non-lignite units, a Hg limit of 0.15 lb/TBtu is estimated to cost $0.81/MWhr with an fPM limit of 0.006 lb/MMBtu and $0.31 lb/MWhr with an fPM limit of 0.0024 lb/MMBtu.

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[7] The original MATS rule used the term "low-rank coals" for lignite coals. In this report, "lignite" and "low-rank" coals are used interchangeably. All other coals are considered not low rank or not lignite.

C. HCl Emissions

ATP finds that significant reductions in HCl emissions are achievable. Data indicate that scrubbed units that comply with the current HCl limit by maintaining sulfur dioxide (SO_2) emissions below 0.20 lb/MMBtu most likely also have HCl emissions below 0.0006 lb/MMBtu. Reducing the HCl emissions limit to 0.0006 lb/MMBtu would impact up to six units with wet scrubbers that could install DSI or upgrade the flue gas desulfurization (FGD) system (the vast majority of units with wet scrubbers emit at a rate at or below 0.0006 lb/MMBtu already), a small number of dry sorbent injection (DSI)-equipped units with ESPs and no baghouses that would need to increase their treatment rate, and some units that do not have any form of flue gas treatment for SO_2 or HCl. These uncontrolled units would, at most, need to install DSI, which is a control technology with modest cost that has been cost-effectively implemented at numerous facilities. All units with dry scrubbers, also known as dry FGD systems, all units with DSI and baghouses, and nearly all units with wet FGD, already have HCl emissions rates under 0.0006 lb/MMBtu. Therefore, this limit would be readily achievable.

D. Time to Comply

As discussed in more detail in this report, three years is more than enough time to comply with the requirements of the proposed rule and the lower emissions limits examined here. The vast majority of units already comply with the fPM limit in the proposed rule with existing controls. The few that do not would mostly need to upgrade their ESPs; two may require baghouses. Many units will need to install PM CEMS, but this can be installed in well under a year. Lignite units can reduce Hg emissions simply by increasing carbon injection rates, which can be performed within months. As a result, except for the small number of units that may need to perform a significant ESP upgrade or perhaps install a baghouse, compliance with the proposed standards should be possible in under a year. ESP upgrades or a baghouse installation may require an additional year.

To comply with more stringent fPM and Hg emission limits, it may be necessary for some units to install baghouses. Even for these units, however, three years is ample time. EPA estimated that the 2012 MATS rule would result in 100 GW of baghouses being installed in three years (with the possibility of a one-year extension). None of the options evaluated here result in deployment of this scale of baghouses. So, three years is adequate for any situation examined here.

Complying with a lower HCl standard of 0.0006 lb/MMBtu would require under two years. The vast majority of units already comply with this emission rate. For those that do not, installation of DSI can be completed within 18 months. A similar length of time would be needed for a wet FGD upgrade. HCl CEMS would require less than a year to install.

II. Analysis Results

There have been important developments in PM, Hg and acid gas controls since the development of the 2012 MATS rule, and these developments impact industry's ability to achieve lower emission levels than required in that rule. In the aforementioned reports, ATP examined the emissions performance of coal-fired facilities using a database that was developed and published by NRDC. This database includes a comprehensive list of coal-fired facilities, their configurations, emissions levels (NO_x, SO_2, PM, HCl, and Hg)

In the April 2023 proposal, EPA has determined that revisions of maximum achievable control technology (MACT) standards established in MATS are warranted:[8]

> *As explained in detail herein, based on this information, the EPA now concludes that developments in the costs and effectiveness of control technologies and the related fact that emissions performance still varies significantly, warrant revising certain MACT standards.*

EPA considers any of the following to be a "development" that could necessitate revisions to standards under section 112(d)(6) of the Clean Air Act:[9]

- *Any add-on control technology or other equipment that was not identified and considered during development of the original MACT standards;*
- *Any improvements in add-on control technology or other equipment (that were identified and considered during development of the original MACT standards) that could result in additional emission reductions;*
- *Any work practice or operational procedure that was not identified or considered during development of the original MACT standards;*
- *Any process change or pollution prevention alternative that could be broadly applied to the industry and that was not identified or considered during development of the original MACT standards; and*
- *Any significant changes in the cost (including cost effectiveness) of applying controls (including controls the EPA considered during the development of the original MACT standards).*
- *Any operational changes or other factors that were not considered during the development of the original MACT standards.*

As discussed in more detail in the 2021 and 2022 ATP reports, there have been "developments" with regard to PM controls, Hg controls, and HCl controls. Further, as will be discussed in this report, ATP has determined that developments in controls and demonstrated

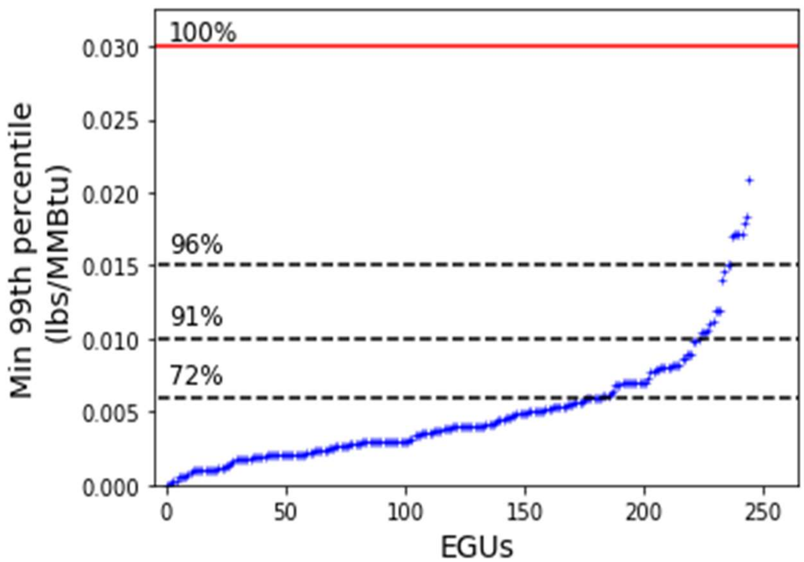
[8] Federal Register / Vol. 88, No. 78 / Monday, April 24, 2023, pg. 24,866.
[9] Ibid., pg. 24,863.

emission rates both indicate that lower emission limits are achievable. The costs of complying with these lower emission limits are estimated below.

A. PM emissions standards

EPA evaluated emissions data and determined that most facilities have in recent years been emitting fPM at rates well below the current standard, as shown in Figure 1.[10] EPA found that 72% of the units had baseline emissions rates[11] at or below 0.006 lb/MMBtu, 91% had baseline emissions rates below 0.010 lb/MMBtu, and 96% had baseline emissions rates at or below 0.015 lb/MMBtu. As will be discussed, this is generally consistent with findings by ATP in our 2021 report: most facilities are controlling emissions to well below the current emissions standard.

Figure 1. fPM baseline emissions rates (lb/MMBtu), sorted from lowest to highest.[12]



EPA also evaluated fPM data and estimated baseline emission rates based upon the primary PM control device. This is shown in Table 1 and graphically depicted in Figure 2. As shown, except for control with wet scrubbers (there are only two units with wet scrubbers as the primary PM control device), median and mean fPM emission rates are on the order of 0.005 lb/MMBtu. The median PM emission rate is generally lower than the mean emission rate because it is not as impacted by high rates as the mean. In the case of units with fabric filters, fPM mean and median emission rates are generally lower than 0.005 lb/MMBtu. Even where the primary PM control

[10] Ibid., pg. 24,868.

[11] EPA defines the baseline emissions of each unit as the 99th percentile of emissions from the lowest quarter by emissions for which data are available. EPA, 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, EPA-HQ-OAR-2018-0794-5789, at 4 (Apr. 2023).

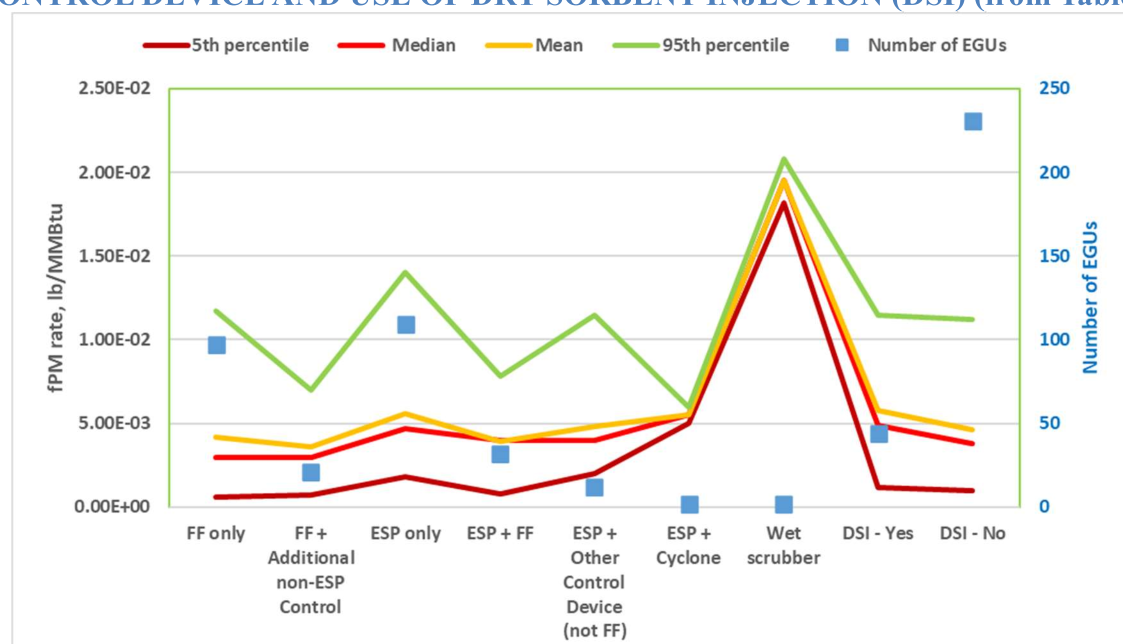
[12] Reproduced, with title replaced, from EPA, 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, EPA-HQ-OAR-2018-0794-5789 (Apr. 2023).

device is an ESP, the mean and median emission rates are around 0.005 lb/MMBtu (median somewhat lower and mean somewhat higher).

Table 1. BASELINE FPM RATES (LB/MMBTU) BASED ON THE PRIMARY PM CONTROL DEVICE AND USE OF DRY SORBENT INJECTION (DSI)[13]

	Technology	Number of EGUs	Baseline fPM Rate (lb/MMBtu)			
			Mean	5th percentile	Median	95th percentile
Primary PM Control Device	FF only	97	4.20E-03	6.00E-04	3.00E-03	1.17E-02
	FF + Additional non-ESP Control	21	3.60E-03	7.00E-04	3.00E-03	7.00E-03
	ESP only	109	5.60E-03	1.80E-03	4.70E-03	1.40E-02
	ESP + FF	32	3.90E-03	8.00E-04	4.00E-03	7.80E-03
	ESP + Other Control Device (not FF)	12	4.80E-03	2.00E-03	4.00E-03	1.15E-02
	ESP + Cyclone	2	5.50E-03	5.00E-03	5.50E-03	6.00E-03
	Wet scrubber	2	1.95E-02	1.82E-02	1.95E-02	2.08E-02
Use of DSI?	Yes	44	5.80E-03	1.20E-03	4.90E-03	1.15E-02
	No	231	4.60E-03	1.00E-03	3.80E-03	1.12E-02

Figure 2. BASELINE FPM RATES (LB/MMBTU) BASED ON THE PRIMARY PM CONTROL DEVICE AND USE OF DRY SORBENT INJECTION (DSI) (from Table 1)



[13] Reproduced from EPA, 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, EPA-HQ-OAR-2018-0794-5789 (Apr. 2023).

EPA also noted comments that stated that their fleetwide evaluation determined that lower emission rates could be achieved at reasonable costs:[14]

> *More specifically, one commenter presented its fleetwide evaluation using data from 100 coal units in the PJM Interconnection and in the Electric Reliability Council of Texas (ERCOT) markets. The commenter's analysis suggested that only 42 EGUs would require additional capital or operating costs to meet a more stringent fPM limit of 7.0E–03 lb/MMBtu, while 79 EGUs would incur those costs to meet a limit of 3.75E–03 lb/MMBtu. The commenter's analysis suggested that most units would incur costs in the range of $0/kW to $75/kW . . . .*

This is notable because an fPM limit of 0.007 lb/MMBtu is less than one fourth the current MATS standard and an fPM limit of 0.00375 lb/MMBtu is one eighth the current MATS standard. It is also notable because the costs that the commenter provided make it clear that these emissions levels would be achievable without addition of a baghouse, which would cost well above $75/kW. The findings by this commenter are consistent with the data visualized in Figure 2 and summarized in Table 1, which show that most coal-fired EGUs are emitting fPM at levels at or below 0.005 lb/MMBtu.

EPA determined that, in light of the low emissions levels and the lower costs of control than it had previously anticipated, it should consider a revision of the fPM standard:[15]

> *Because an evaluation of compliance data showed that a significant portion of coal-fired EGUs are performing well below the allowed emission limit (Figure 1), and because the EPA obtained information indicating lower costs to improve controls to achieve additional fPM emission reductions than assumed during promulgation of the original MATS fPM emission limit, the EPA concluded that there were developments that warranted an examination of whether to revise the standard.*

EPA also determined that the costs of PM controls are likely much lower than the agency estimated in 2012:[16]

> *. . . data received since 2012 demonstrates that the costs of PM control upgrades are likely much lower than the EPA estimated in 2012.*

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[14] Federal Register / Vol. 88, No. 78 / Monday, April 24, 2023, pg. 24,868 (discussing comment submitted by Calpine Corporation, EPA-HQ-OAR-2018-0794-5121).

[15] Ibid.

[16] Ibid., pg. 24,869.

This is consistent with 2015 findings by ATP. In 2015, ATP[17] demonstrated that EPA significantly overestimated the cost of the 2012 MATS rule. A substantial portion of the overstated cost resulted from EPA's overestimate of the need for fabric filters by roughly 100 GW of generating capacity. As will be discussed later, assumed deployment of fabric filters versus other, less costly approaches for reducing emissions has a large impact on the forecast of the cost to comply with any fPM emission limit, or other emission limits where a fabric filter may play a role in emissions capture.[18] The cost savings will be determined by both the potential for other options – such as ESP upgrades – to reduce emissions and the cost of those other options.

2. ATP 2021 findings

In the 2021 report, ATP examined the PM emissions performance of coal-fired facilities using a database that was developed and published by NRDC.[19] This database included a comprehensive list of coal-fired facilities, the unit characteristics (including capacity and air pollution control configuration), and emission rates (SO_2, PM, Hg, and HCl, where available). Units for which 2019 fPM emission rates were available were sorted into deciles, from the lowest-emitting units to the highest-emitting units. As shown in Figure 3, the top eight deciles have average PM emissions below 0.01 lb/MMBtu. This is roughly consistent with EPA's findings in Figure 1, except that EPA's analysis indicates even lower emissions. Also, as noted in the 2021 ATP report, an Upper Prediction Limit (UPL) calculated with 2019 data is roughly one sixth of the UPL developed in 2011 for the original MATS rule.

The 2021 ATP report also examined the equipment used in each decile. Figure 4 shows that the top deciles are more likely to have a baghouse and dry FGD than are lower-performing deciles. This is not surprising; however, there are some facilities in the top deciles that do not have baghouses, and some with just ESPs and no scrubbers. PM CEMS are also used for demonstrating compliance in a majority of units for all deciles, except for the two highest-emitting deciles (deciles 9 and 10). Further, ACI is used in a majority of the lowest-emitting units, indicating that ACI does not adversely impact PM emissions. Figure 5indicates a relationship between the age of the equipment and PM emissions: the highest-emitting units have the oldest equipment, especially with regard to scrubbers and ESPs.

In any event, it is clear from this analysis that:

- fPM emissions are generally being maintained at levels far lower than anticipated in the MATS rule.

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[17] Staudt, J., Declaration before United States Court of Appeals for the District of Columbia Circuit, September 23, 2015, available at: https://www.andovertechnology.com/wp-content/uploads/2020/09/Staudt-Declaration_2015_09_24_13_19_52-2.pdf.

[18] ACI and DSI can very effectively capture Hg and HCl, respectively, without a fabric filter; however, a fabric filter can improve capture further.

[19] The NRDC database includes some units that were later identified for retirement and are not included in EPA's analysis for the proposed rule. So, there will be some significant differences.

- The cost of controls is much lower than previously estimated, and the capabilities of controls are greater.
- The age of the equipment installed appears to be associated with fPM emissions rates, with newer equipment having lower emissions.

Figure 3. Average fPM emissions (lb/MMBtu) by decile[20]

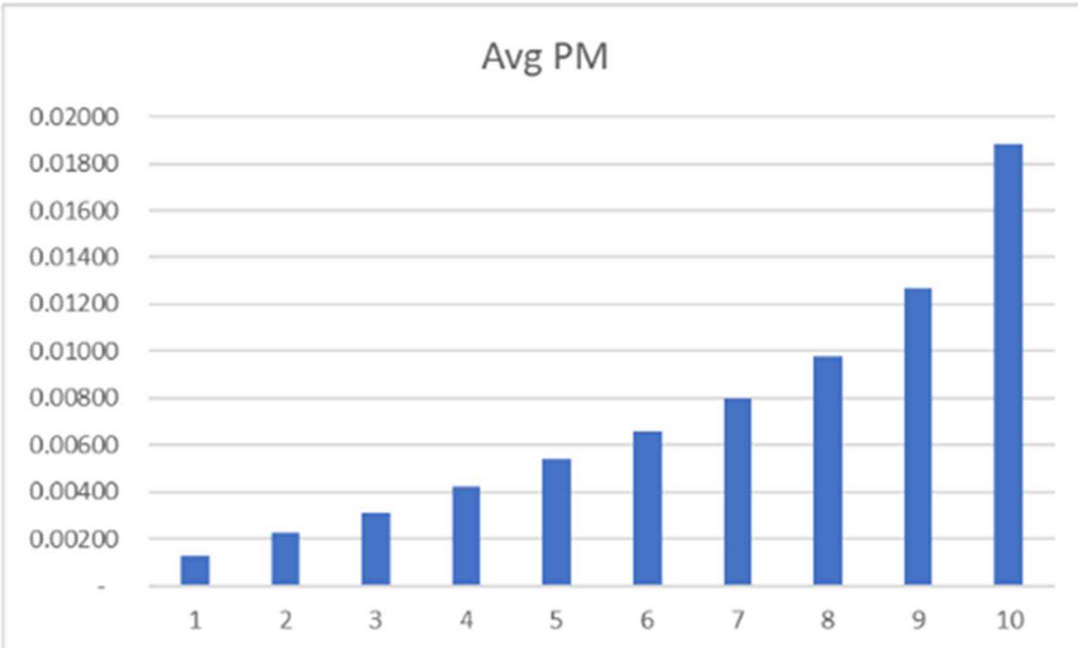
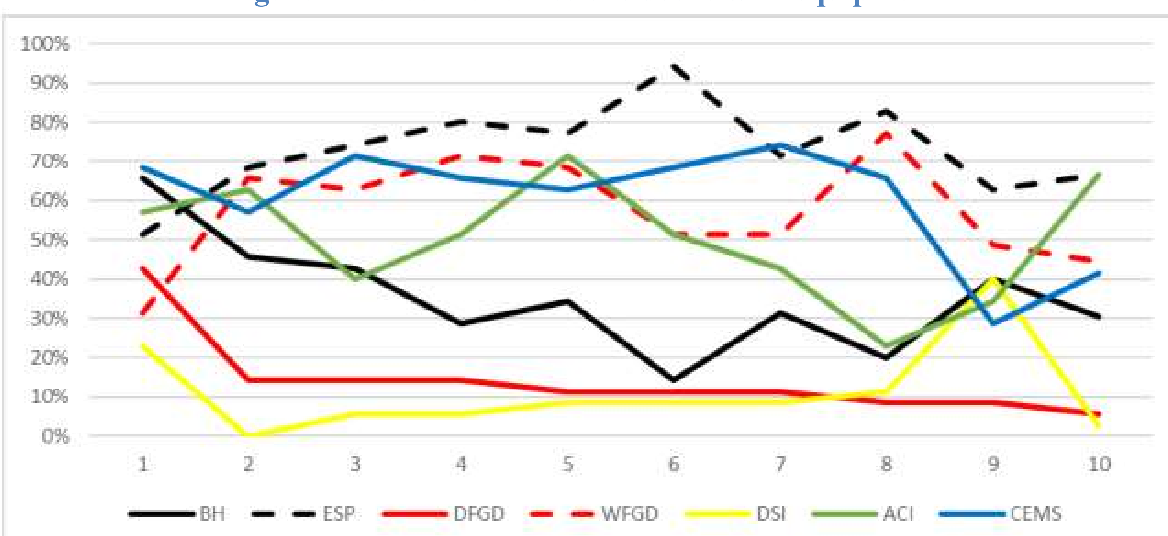


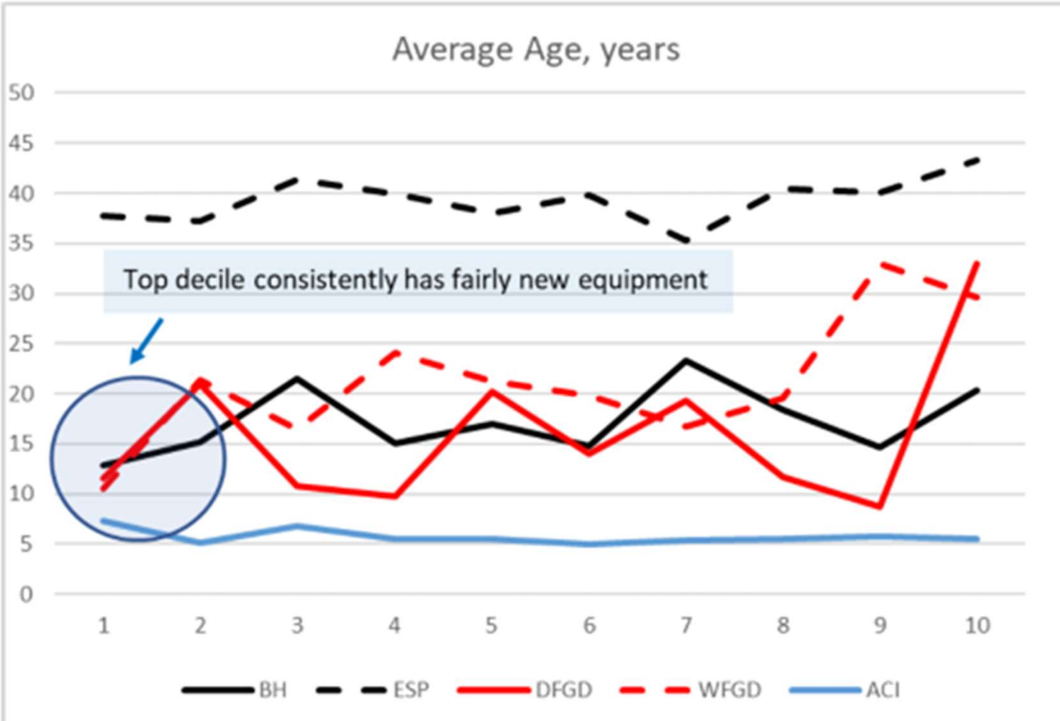
Figure 4. Percent of emissions decile with equipment[21]



[20] Staudt, J., *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants, for* Center for Applied Environmental Law and Policy (CAELP), August 19, 2021.

[21] Ibid.

Figure 5. Average age of equipment in emissions decile



3. Considerations for the cost and performance of PM controls

ATP's 2021 analysis and later 2023 addendum, among other things, examined the cost to control PM emissions to different levels. The underlying assumptions are discussed in those documents. In developing its estimate of the cost of the proposed rule, EPA used assumptions about the cost and fPM reduction potential of fPM control technologies reflecting estimates from Sargent & Lundy.[22] Notably, among other statements in that memo, Sargent & Lundy indicated that the lowest fPM guarantee offered by manufacturers of ESPs is 0.03 lb/MMBtu and 0.010 lb/MMBtu for fabric filters.[23] This is incorrect. Lodge Cottrell, a supplier of ESPs and ESP rebuilder, indicated in a 2008 presentation to air regulators that ESP performance guarantees for coal-fired utility boilers were as low as 0.010 lb/MMBtu – one third of what Sargent & Lundy claimed the lowest guarantee in 2023.[24] Andritz offers outlet emission rates lower than 2 mg/dscm

[22] Sargent & Lundy, "PM Incremental Improvement Memo – Final", March 2023, EPA-HQ-OAR-2018-0794-58356.

[23] Ibid., pg. 2.

[24] R. Mastropietro, "Electrostatic Precipitator Rebuild Strategies For Improved Particulate Emissions", this presentation by Lodge Cottrell to the Mid Atlantic Air Management Association in 2008. https://s3.amazonaws.com/marama.org/wp-content/uploads/2008/07/13093303/Mastropietro_ControlTech08.pdf

for fabric filters, which is about 0.0027 lb/MMBtu.[25] So, Sargent & Lundy's statement regarding guarantees offered by fPM suppliers is both incorrect and unreliable. It is also fair to say that technology suppliers respond to the need of the market, and as emission standards decrease, suppliers often find ways to improve guarantees. It would be reasonable that guarantees offered in 2023 would be lower than those offered in 2008 – prior to MATS.

Table 2 shows EPA's modeling assumptions for ESP upgrades. EPA assumes that there are three different types of ESP upgrades, and

For facilities with ESPs and no baghouse (FF), EPA assumed:

For units with an existing ESP and no FF, we assume that the ESP upgrades summarized in Table 4 would be necessary to reduce fPM to either 1.5E-02 or 1.0E-02 lb/MMBtu. We assumed the maximum potential performance improvement associated with the upgrade options (i.e., 10% reduction for minor upgrades and 20% reduction for typical upgrades). In order to reduce fPM to 6.0E-03 lb/MMBtu or below, the EPA assumes that a FF is required. For EGUs with an existing ESP and without an existing FF, we assume the baseline fPM rate will decrease by 90 percent, with a maximum reduction to 2.0E-03 lb/MMBtu.

Table 3 summarizes the technology and fPM rate assumptions used in the modeling.

Table 2. Sargent & Lundy modeling assumptions for ESP upgrades[26]

Option	Minor Upgrades (Low Cost)	Typical Upgrades (Average Cost)	ESP Rebuild (High Cost)
Estimated Cost	\$6-\$27 / kilowatt (kW)	\$45-\$65 / kW	\$75-\$100 / kW
Potential Performance Improvement (Not Guaranteed Performance)	5%-10% reduction in fPM emissions; not applicable to units with current emission rates ≤ 0.010 lb/MMBtu	10-20% reduction in fPM emissions; not applicable to units with current emission rates ≤ 0.010 lb/MMBtu	Performance limited to 99.9% fPM removal (clean conditions)

For facilities with ESPs and no baghouse (FF), EPA assumed: [27]

For units with an existing ESP and no FF, we assume that the ESP upgrades summarized in Table 4 would be necessary to reduce fPM to either 1.5E-02 or 1.0E-02 lb/MMBtu. We assumed the maximum potential performance improvement

[25] https://www.andritz.com/environmental-solutions-en/air-pollution-control/technologies-air-pollution-control/dedusting-air-pollution-control/fabric-filter-air-pollution-control; 4.4 mg/dscm is roughly 0.006 lb/MMBtu (88 CFR 24874)

[26] Reproduced, with title replaced, from EPA, 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, EPA-HQ-OAR-2018-0794-5789 (Apr. 2023).

[27] EPA, 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, EPA-HQ-OAR-2018-0794-5789, at 9-10 (Apr. 2023).

associated with the upgrade options (i.e., 10% reduction for minor upgrades and 20% reduction for typical upgrades). In order to reduce fPM to 6.0E-03 lb/MMBtu or below, the EPA assumes that a FF is required. For EGUs with an existing ESP and without an existing FF, we assume the baseline fPM rate will decrease by 90 percent, with a maximum reduction to 2.0E-03 lb/MMBtu.

Table 3—SUMMARY OF TECHNOLOGY AND FPM RATE ASSUMPTIONS FOR DIFFERENT PM CONTROL DEVICES[28]

	Potential fPM Standards (lb/MMBtu)					
PM Control Device	1.5E-02		1.0E-02		6.0E-03	
	Technology Assumption	Assumed fPM Rate (lb/MMBtu)	Technology Assumption	Assumed fPM Rate (lb/MMBtu)	Technology Assumption	Assumed fPM Rate (lb/MMBtu)
ESP only	ESP upgrade	1.5E-02	ESP upgrade	1.0E-02	New FF installation	90% reduction from baseline, up to 2.0E-03 lb/MMBtu
FF only or FF in combination with other PM controls	FF bag upgrade	6.0E-03	FF bag upgrade	6.0E-03	FF bag upgrade	6.0E-03
Wet Scrubber	WS maintenance/ ESP upgrade	1.5E-02	New FF installation	90% reduction from baseline, up to 2.0E-03	New FF installation	90% reduction from baseline, up to 2.0E-03

The assumptions EPA uses are inconsistent with EPA's data and with ATP's prior findings in the following ways:

- EPA's assumed reductions of fPM emission rates that result from ESP upgrades are less than previously found in ATP work (and also less than demonstrated by actual fPM emissions data).
- EPA's assumed fPM emission levels associated with ESP upgrades are inconsistent with the emissions data that EPA presented in the rule.

The impact of these assumptions is that more fabric filter retrofits are likely to be estimated in EPA's modeling than would, in fact, occur for most emission rate standards. The impact on projected cost will be that, for some emission standards, EPA will estimate too high of a cost. At sufficiently low emissions rates, virtually every unit will require a baghouse. Each of these points and other estimates of cost are presented in the following sections.

[28] Reproduced, with title replaced, from EPA, 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, EPA-HQ-OAR-2018-0794-5789 (Apr. 2023).

a. EPA's assumed reduction of fPM emission rates that result from ESP upgrades are less than previously found in ATP work (and also less than demonstrated by actual fPM emissions data).

ATP examined different types of ESP upgrades in the 2021 report (in this case, "upgrade" includes simply repairing the existing ESP in one way or another without adding new, more modern components, repairing with in kind components, or actual upgrades with new or improved ESP technology). These included:

Repairing casing leaks and/or improve flow balancing:

- This does not impact ESP internals, and simply improves flow characteristics of the ESP.
- Usually, this is a relatively inexpensive improvement. This is not expected to cost much more than about $20/kW, depending upon what is actually done – in many cases less than $20/kW.
- A 20% reduction in flow will yield a 25% increase in treatment time – equating to roughly a 40% reduction in PM emission rates.
- Arguably, this is normal maintenance. But, for most facility owners, the ESP has never been a large priority.

Repairing the ESP with in-kind equipment:

- Repair or replacement of failed insulators, electrodes, or even plates can restore performance and yield 20%-30% improvement or more, depending upon the defect being corrected.
- Costs depend upon the nature of repair but generally are about $20/kW or less.
- Arguably, this also is normal maintenance. But, for most facility owners, the ESP has never been a large priority.

Installing High Frequency Transformer Rectifier Sets (HFTR):

- This entails changing the control electronics and power supplies.
- Installing HFTR can yield on the order of 20%-30% improvement or more at a cost of about $10/kW or frequently less.

Improving ESP Reliability – upgrade to newer or more reliable components, even if not damaged:

- Cost and performance improvement will vary depending upon what is done.

Complete rebuild within existing casing (aka, "gut and stuff")

- This is less of a major upgrade as much as a restoration of the ESP to "like-new" condition, or better.

- An example was given in the 2021 report with emission reduction of 91% to 0.00343 lb/MMBtu.
- Cost would be about $50/kW and will vary depending upon the specifics of the ESP.

Increasing the casing volume to increase treatment time

- The cost is normally between $50/kW and $80/kW, perhaps higher in some cases. Additional fields for an ESP have been estimated to be in the range of $65/kW for some projects. Increasing the casing volume will often include HFTR upgrade.
- A roughly one-third increase in treatment time will reduce emissions by about 50% and a roughly two-thirds increase in treatment time will reduce PM emissions by about 70%.

Therefore, similar to what Sargent & Lundy and EPA assumed, there are a range of upgrade options; however, the ESP upgrades and modifications discussed above provide higher emission reductions than EPA or Sargent & Lundy has assumed. In the following paragraphs, data will be examined that demonstrates that greater emission reductions are, in fact, occurring from ESP upgrades. Of course, some of the above improvements can be performed together for better performance than if one of the improvements was performed alone. The costs and performance estimates presented in the 2021 report were developed based upon information that ATP had collected on dozens of planned utility projects.

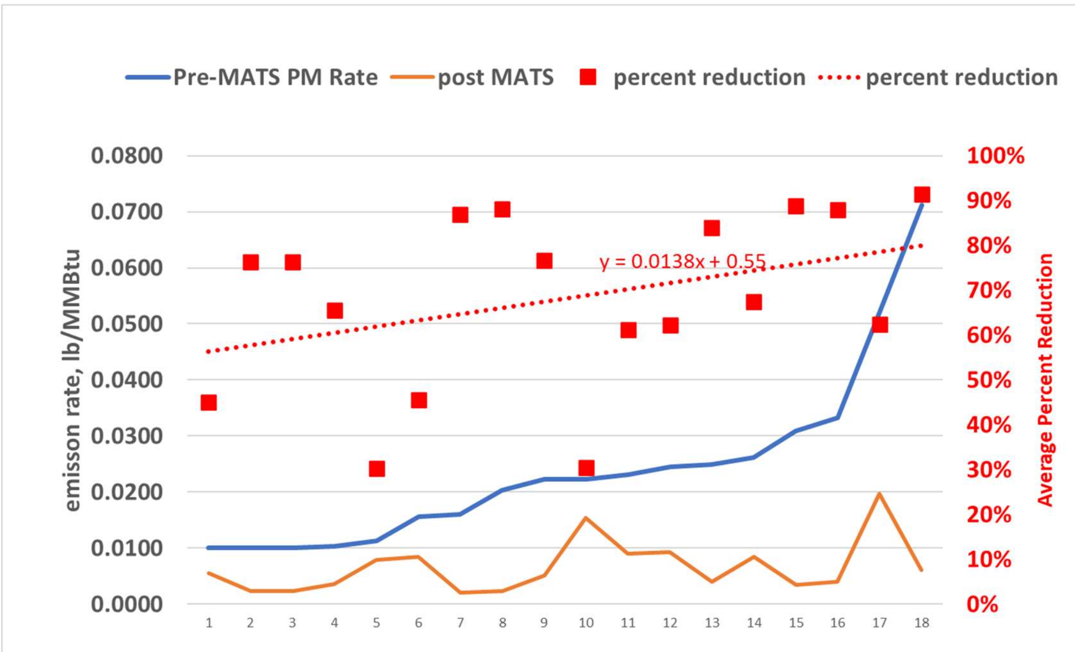
The estimates of PM emission rate reduction by ESP upgrades can be ascertained through examination of actual emissions data, as discussed in the next paragraph.

Because data on ESP upgrades are not publicly disclosed in EIA Form 860 or other Federal filings, information on upgrades must be inferred from PM emissions data. Where there has been a significant improvement in PM emissions and no other change to air pollution control, it may be inferred that an ESP upgrade of some sort has been performed. To examine this, for this report ATP examined performance of facilities that had ESPs prior to MATS and continued to operate with ESPs as the primary control device (no baghouse or scrubber) after MATS. Given that the MATS standard is 0.03 lb/MMBtu, facilities with pre-MATS fPM emission rates below 0.010 lb/MMBtu had little incentive to upgrade their ESPs. Thus, ATP collected pre-MATS emissions data for 18 EGUs with pre-MATS rates at or greater than 0.010 lb/MMBtu and with ESPs as the only pollution control device both before and after MATS, and available post-MATS emissions data for these units.[29] The results are shown in Figure 6, with data sorted from the EGU with the lowest pre-MATS fPM rate (at or above 0.010 lb/MMBtu) to the highest pre-MATS rate. The blue line is the pre-MATS rate. The orange line is the post-MATS rate for that unit. The red dots are

[29] Data from the Information Collection Request (ICR) for the 2012 MATS rule were used for pre-MATS emission rates. EPA's unit-level data from Appendix B of the 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category were used for post-MATS emission rates.

the percent reduction in fPM emissions from before MATS to after MATS. Percent emission reduction was calculated by comparing the post-MATS fPM rate to the pre-MATS rate. As shown, fPM emission reductions are generally well above what EPA assumed, and in many cases are even well above 80%. The trendline shows a slight increase in percent reduction with higher initial PM emission rate, which is expected. In most cases, final fPM emissions are well below 0.010 lb/MMBtu. This data clearly shows that actual fPM emission reductions from ESP upgrades are often quite significant, and are generally much greater than what was assumed by EPA.

Figure 6. Comparison of pre-MATS to post-MATS fPM emissions for units with ESPs as the only PM control device and pre-MATS emission rate of 0.010 lb/MMBtu or greater



b. EPA's assumed PM emission levels associated with ESP upgrades are inconsistent with the emissions data that EPA presented in the rule.

As shown in Figure 2 and Table 1, the mean and median fPM emissions rate data collected by EPA and shown in the proposed rule are about 0.005 lb/MMBtu for units with ESPs alone as the primary PM control device. Figure 7 shows the data EPA used in developing the rule for cold-side ESPs[30] listed from lowest fPM rate to highest fPM rate. As shown, fPM rates at or below 0.0027 lb/MMBtu are achieved at 20% of the units, and half of the units have fPM emission rates of 0.0046 lb/MMBtu or less. Over 90% of the cold-side ESP-equipped units had fPM rates at or below 0.010 lb/MMBtu. On the other hand, EPA's assumptions for PM reductions in

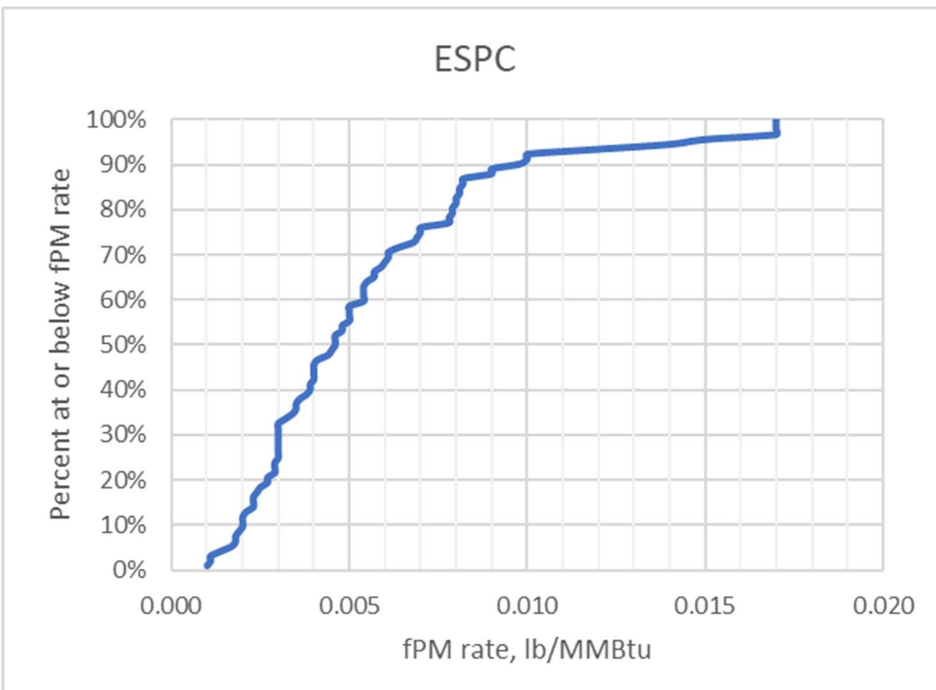
[30] Cold-side ESPs are the most common form of ESP. There are very few hot-side ESPs. So, cold-side ESPs are of most interest.

For facilities with ESPs and no baghouse (FF), EPA assumed:

For units with an existing ESP and no FF, we assume that the ESP upgrades summarized in Table 4 would be necessary to reduce fPM to either 1.5E-02 or 1.0E-02 lb/MMBtu. We assumed the maximum potential performance improvement associated with the upgrade options (i.e., 10% reduction for minor upgrades and 20% reduction for typical upgrades). In order to reduce fPM to 6.0E-03 lb/MMBtu or below, the EPA assumes that a FF is required. For EGUs with an existing ESP and without an existing FF, we assume the baseline fPM rate will decrease by 90 percent, with a maximum reduction to 2.0E-03 lb/MMBtu.

Table 3 assume that baghouses are necessary to achieve PM emission rates below 0.010 lb/MMBtu. Clearly, this assumption does not comport with the data that EPA presents in the rule. It is apparent that most EGUs with ESPs and no fabric filter are already achieving well below 0.010 lb/MMBtu.

Figure 7. fPM rates for units with cold-side ESPs[31]



EPA also assumed that the most-costly ESP upgrade of the options they considered (ESP rebuild) was limited to 99.9% overall capture efficiency. Looking at the IPM data on coals (see Chapter 7, Table 7-4 of the IPM documentation), the average ash content of Wyoming coals is about 8.3 lb/MMBtu, the average ash content of Illinois Basin coals (Illinois, Kentucky, and Indiana) is about 7.8 lb/MMBtu, and the average ash content across all coals listed is 10.4

[31] Developed from EPA, 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, EPA-HQ-OAR-2018-0794-5789, Appendix C (Apr. 2023).

lb/MMBtu.[32] Even assuming 80% of the coal ash becomes fly ash (the remainder being bottom ash), this means that the *lowest* emission rate for an ESP with an upgrade is about 0.006 lb/MMBtu, which of course is greater than the mean and median emission rate for EGUs where ESPs are the sole control device. As a result, this assumption of a 99.9% maximum capture efficiency is too low. fPM capture rates greater than 99.9% are clearly being achieved in operating ESPs.

EPA's assumptions about the ability of ESPs to achieve low emissions (with or without upgrades) are inconsistent with EPA's own data used to develop the rule. It is apparent that ESPs can achieve significantly lower emission rates than what was assumed by EPA in estimating the cost of the rule. This results in EPA overestimating the need for baghouses, and therefore overestimating the cost of the rule because baghouses are much more costly than upgrades to ESPs.

4. Estimate of cost to comply with emission rates

ATP assessed the costs to comply with lower fPM standards in the 2021 report. In today's report, ATP is updating the cost estimates. ATP's estimate uses the data and units identified in Appendix C of the 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category.

a. Cost modeling approaches – ATP versus EPA

ATP modeled each of the units that EPA identified to be operating after 2028 and evaluated each one in a Microsoft Excel workbook assuming that every unit would continue to operate at a 50% capacity factor. ATP assumed each modelled unit would control to 20% below the stated emission rate standard. For example, if the evaluated standard was 0.010, it was assumed that units would need to control to at or below 0.008 lb/MMBtu. This also means that units with a baseline emission rate of 0.009 lb/MMBtu would need to reduce emissions even though the proposed emission standard is higher, at 0.010 lb/MMBtu.

Appendix D of EPA's 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category shows the projected cost for units identified as operating through 2028 that are projected by EPA to require an expenditure. These units were evaluated on a unit-by-unit basis with individual and total costs shown in that document.

EPA also conducted modeling using the Integrated Planning Model (IPM). EPA incorporates their fPM cost modeling assumptions into IPM, which is a comprehensive electric energy modeling platform that makes economic dispatch decisions and decisions about retirement and construction of facilities. Unlike ATP's modeling, which assumes that all facilities continue to operate, with IPM some facilities may be retired, depending upon a variety of factors, including if the cost of bringing a unit into compliance makes it uneconomical. EPA's baseline forecast is the "post-IRA"[33] case. The baseline forecast included 56 GW of coal retirements by 2028, and some of the retired units are units that are included in ATP's analysis as well as in EPA's Appendix

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[32] https://www.epa.gov/system/files/documents/2023-03/Chapter%207%20%E2%80%93%20Coal.pdf

[33] IRA is the Inflation Reduction Act of 2022, which includes policies to promote lower-carbon energy sources.

D. This is the baseline that the policy cases are compared to. For the proposed rule, the projection was 57 GW of coal retirements and 69 GW of coal retirements for the more stringent regulatory alternative, which includes the fPM standard of 0.006 lb/MMBtu that EPA evaluated.[34] The incremental retirements over the baseline for the two policy cases that were evaluated were therefore 1 GW for the proposed rule and 13 GW for the more stringent regulatory alternative. A retirement avoids the cost of a retrofit to comply with a rule and will occur if IPM calculates that a retrofit is a less economical solution than retirement and getting that generation from another unit. Therefore, IPM modeling suggests that actual costs of a rule will be less than the unit-level costs discussed here.

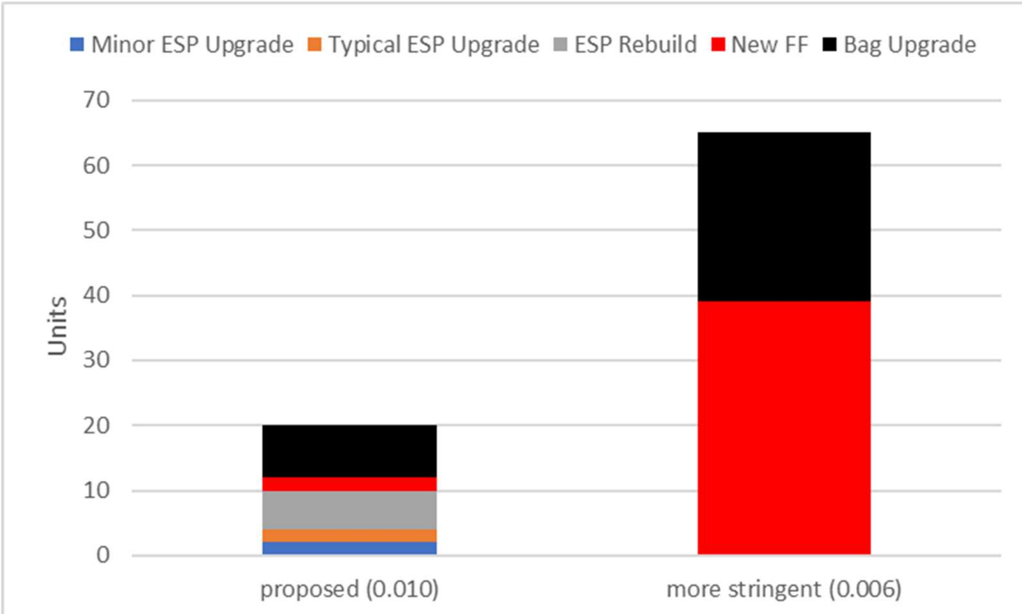
The unit-level control assumptions for EPA's proposed option and more stringent alternative are found in EPA's Post-IRA 2022 Reference Case Documentation Supplement Supporting RIA Analysis of Proposed MATS RTR.[35] These show the control requirements for those units that EPA determined needed controls to comply with the fPM standard. Sixty-five units were identified that required controls under the standards that EPA evaluated. For the proposed standard, two new fabric filters were required, ten ESP upgrades of one sort or another, and 8 fabric filter upgrades (new filter bags for existing baghouses). A total of 20 units were retrofit in one manner or another. For the "more stringent" standard 65 units were identified for needing retrofit, with 39 installing new fabric filters and 26 upgrading their fabric filters. This is shown in Figure 8. IPM might determine that some of these facilities will retire rather than install this equipment, but that is not shown here.

ATP's modeling method will have different results primarily for two reasons:

1) ATP assumed a control margin, which will tend to increase the projected number of retrofits or potentially more significant ESP upgrades
2) ATP makes different assumptions regarding the potential emission reductions from ESP upgrades

[34] See IPM modeling output, available for download at https://www.epa.gov/power-sector-modeling/analysis-proposed-mats-risk-and-technology-review-rtr.
[35]https://www.epa.gov/system/files/documents/2023-04/Supplemental%20Modeling%20Documentation.pdf

Figure 8. fPM upgrade types projected by EPA for the proposed standard and for the more stringent standard



b. fPM retrofit cost assumptions

ATP assumed a control level of 20% below the emission standard to provide a degree of compliance margin. ATP's cost assessment is therefore more conservative than EPA's in this regard, as EPA did not assume any retrofits or upgrades to controls for units emitting at or below each standard that EPA examined.[36]

ATP uses different fPM retrofit assumptions than EPA does. Also, in this update, ATP is assuming the costs of reducing emissions from ESP-equipped units as shown in Table 4 provided that the emission standard is not below a threshold (to be discussed later). The assumptions of Table 4 are conservative because the actual data support higher capture rates for ESP upgrades in most cases. If greater than 55% reduction is needed, a fabric filter retrofit is assumed and the capital and operating costs are determined by the Sargent & Lundy cost estimating method.[37]

Table 4. Assumed capital cost for ESP upgrades and FF installations

Upgrade	Minor	Medium	Major	Baghouse
Retrofit cost $/kW	20	50	80	S&L
Reduction over	0%	20%	40%	55%
Up to	20%	40%	55%	

[36] See EPA, 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, EPA-HQ-OAR-2018-0794-5789, Appendix D (Apr. 2023).

[37] Sargent & Lundy, "IPM Model – Updates to Cost and Performance for APC Technologies Particulate Control Cost Development Methodology – Final", April 2017. This model includes cost for DSI. The DSI portion of the cost model was excluded. Because most current fabric filters are pulse jet (PJFF) and these would all be installed where there is an existing ESP, an air to cloth ratio of 6 was assumed.

An additional conservative assumption was made for the lowest emission standards evaluated. This assumption was to default to a baghouse in some cases where a unit is currently equipped with an ESP. The BH default rate is a conservative assumption that is designed to account for the fact that, as the baseline emission rate is lowered, ESP upgrades are likely to be less effective (achieving a lower reduction in fPM emissions than at higher baseline rates). The BH default rate is a threshold baseline emission rate above which it is assumed that an ESP upgrade will not be sufficient to reach the limit even if the percent reduction is within the range for an ESP upgrade shown in Table 4. As a result, a lower BH default rate will increase the number of baghouse installations. When a new PM standard is at or below a BH default rate of 0.0027 lb/MMBtu (the emission rate where 20% of the ESP-only units had emissions at or below), any unit that did not already have emissions below the threshold BH default rate is assumed to install a baghouse, even if the degree of reduction is below the degree of reduction achievable through an ESP upgrade, as indicated in Table 4. For an emission standard of 0.0015 lb/MMBtu, this threshold was reduced to 0.0018 lb/MMBtu. What follows is an example of how the BH default rate works. If the baseline emission rate of an ESP-equipped unit is 0.0020 lb/MMBtu and the emission standard is 0.0015 lb/MMBtu, if not for the BH default rate, an ESP upgrade per Table 4 could achieve the target control emission rate (with a 20% compliance margin) of 0.0012 lb/MMBtu. However, with a BH default rate of 0.0018, the unit will install a baghouse instead.

A capital recovery factor of 11% is assumed.

When an existing fabric filter equipped unit requires a reduction in emissions, an ongoing cost equal to $650/MW-yr is assumed to account for the annual cost of more frequent fabric filter replacement. This is roughly consistent with the assumption used by EPA.[38]

Applying these assumptions, ATP estimated the cost to comply with fPM emissions standards of:

1. 0.015 lb/MMBtu
2. 0.010 lb/MMBtu
3. 0.006 lb/MMBtu
4. 0.004 lb/MMBtu
5. 0.0024 lb/MMBtu
6. 0.0015 lb/MMBtu

The annualized costs in 2019 dollars are shown in Figure 9 along with EPA's estimated costs for emission standards of 0.015 lb/MMBtu, 0.010 lb/MMBtu and 0.006 lb/MMBtu.[39] (EPA

[38] ATP examined the facilities estimated by EPA and made an average of the cost when represented in terms of $/MW-yr. Also, in the prior 2021 and 2023 ATP reports, a $5/kW capital charge was assumed along with annual O&M costs of 2% of capital. On an annualized basis, this is roughly the same as the assumed cost of $650/MW-yr.

[39] EPA's total costs include costs associated with controlling Hg from lignite units. However, this is a small portion of the total cost shown here.

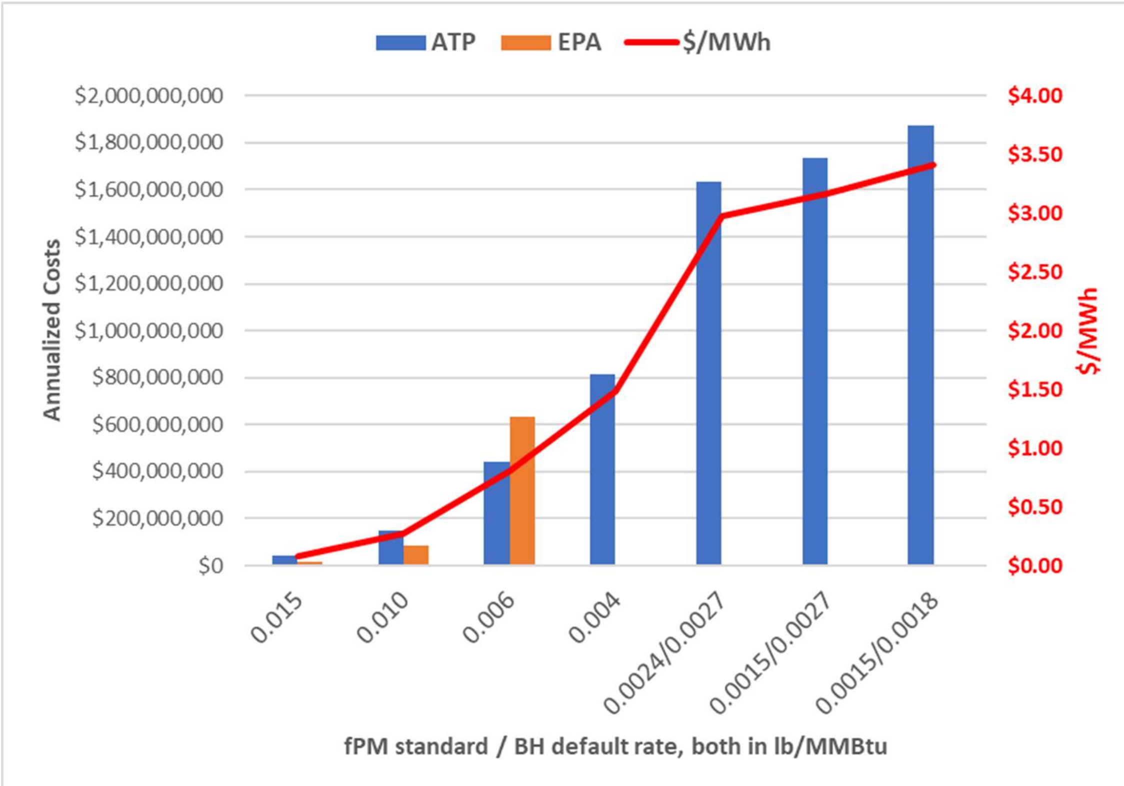
did not assess the costs for lower fPM standards.) For emission standards of 0.015 lb/MMBtu and 0.010 lb/MMBtu, ATP predicts a higher cost of compliance, which is expected because EPA does not use a compliance margin and ATP will project more upgrades. ATP's estimate is significantly lower than EPA's estimate at an emission standard of 0.006 lb/MMBtu. At this emission rate the assumptions about fPM modeling become more important.

As noted earlier in this report, ESP upgrades are capable of greater PM reductions and lower emission rates than assumed by EPA. As a result of EPA's assumptions, for emission standards below 0.010 lb/MMBtu, EPA's fPM modeling assumptions are more likely to predict that a baghouse is needed. Figure 10 shows the types of upgrades that are predicted by ATP to occur for different facilities that are not already equipped with a baghouse. As shown, as the emission standard is decreased, the number of total ESP upgrades increases. Also, the type of ESP upgrade generally becomes a more expensive type, with installation of a new baghouse more frequent as the emission standard is lowered. At 0.0024 lb/MMBtu, an emission limit below the baghouse default rate, any facility with a baseline emission rate higher than 0.0027 lb/MMBtu will default to a baghouse. At an emission rate of 0.0015 lb/MMBtu, two baghouse threshold rates were examined – 0.0027 lb/MMBtu and 0.0018 lb/MMBtu. At the higher of the two rates there are 20 ESP upgrades and 91 fabric filter retrofits predicted, and at the lower of the rates 4 ESP upgrades are predicted and 107 fabric filter retrofits predicted.

Figure 11 compares the projection of new baghouse installations estimated by ATP and the number estimated by EPA under three emission standards – 0.015 lb/MMBtu, 0.010 lb/MMBtu and 0.006 lb/MMBtu. As shown, ATP and EPA are consistent for the two emission standards of 0.015 lb/MMBtu and 0.010 lb/MMBtu. For 0.006 lb/MMBtu, ATP projects 11 baghouse retrofits compared to 39 for EPA.

As previously mentioned, in light of data on ESP upgrades, ATP firmly believes that the results presented here over-predict the cost for compliance with the associated standard because the assumed emission reduction of ESP upgrades is conservatively low for any given cost. This is confirmed by a comparison of Figure 6 to the assumptions in Table 4. ATP's assumptions for the emission reduction of ESP upgrades – while conservatively low – are much more consistent with actual data than EPA's assumptions.

Figure 9. Total, fleetwide, annualized costs of compliance with different fPM emission standards/BH default rates, ATP versus EPA (costs presented in 2019 dollars)[40]



[40] EPA's cost includes some of the cost to control Hg from lignite units, which is a very small part of the total cost shown here.

Figure 10. ATP estimated ESP upgrade types (major, medium, minor), new BH installations, or FF bag upgrades for compliance with different fPM emission standards/BH default rates (lb/MMBtu)

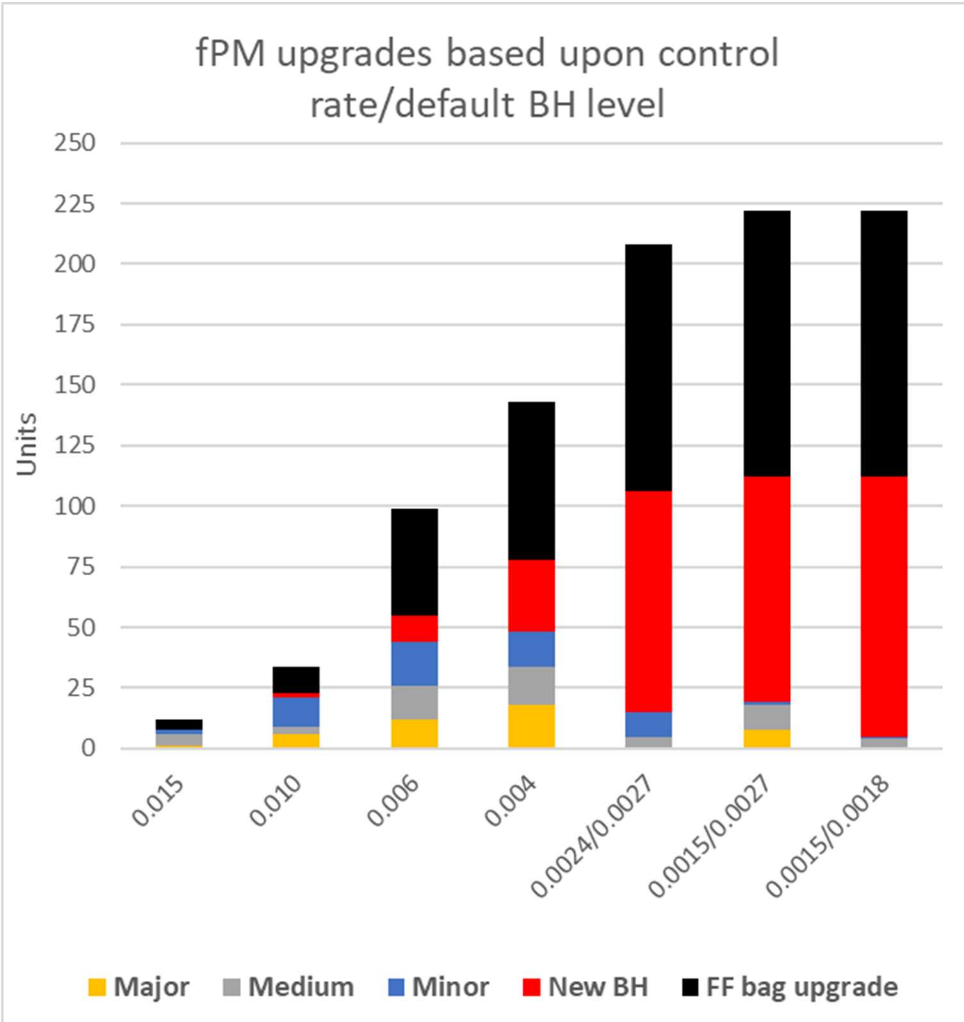
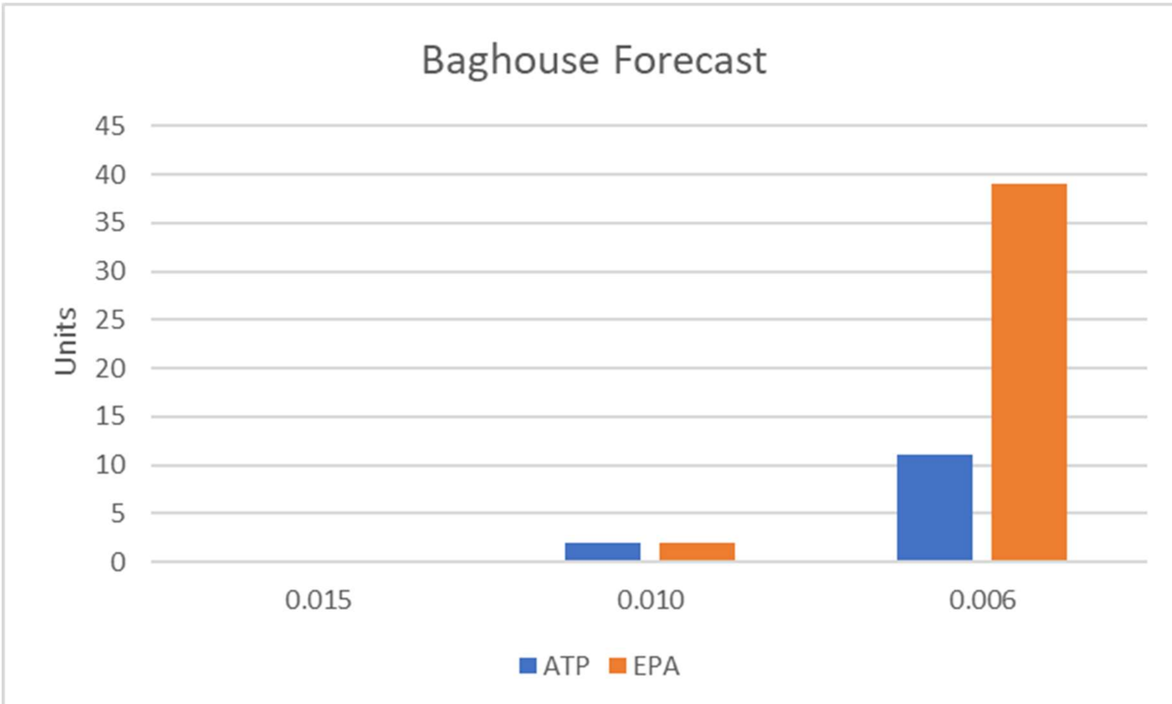


Figure 11. Comparison of new baghouse forecasts for different fPM emission standards (lb/MMBtu), ATP versus EPA



B. PM CEMS

There are two matters worth examining with regard to PM CEMS. They are as follow:

- Developments since the 2012 MATS rule
- Ability to measure to lower levels

1. Developments since the 2012 MATS rule

The PM CEMS technology that was prevalent at the time of the 2012 MATS rule was beta gauge, as well as some other, less widely used methods. Beta gauge operates by irradiating a sample that is collected on a tape with beta radiation and then measuring the radiation given off by that sample. This technology has largely been supplanted by light scattering devices that have advantages relating to cost and sensitivity. Light scattering devices sense the mass density by the light scattering observed in the duct. These devices can be forward scattering (light source and sensor opposite one another) or back scatter (light and sensor on the same side). Today, light scattering devices are more likely to be sold than beta gauge devices.

The main concern with any of these methods is calibration and comparison to a reference method (RM), EPA Method 5, which leads to the next issue.

2. Ability to measure to lower levels

Measuring fPM in a stack is different from gaseous measurements because PM can stratify more so than gaseous species. As a result, getting a single point measurement that accurately represents the total emissions in a duct or chimney is more difficult with PM than with gaseous species. This is why each PM CEMS must be calibrated to the application. Also, fPM in a PM CEMS is inferred from another measurement,[41] and there must be a reliable means to relate concentration to what is actually being detected or measured.

For PM CEMS, it is necessary to develop a calibration curve that is compared to a reference method (Method 5, or M5, for PM or Method 5I) taken at different sample points in the duct. Industry is most comfortable with Method 5, as opposed to Method 5I, and therefore EPA has focused on examining this method for developing calibrations. Method 5 involves collecting a sample of PM over time, and at different locations in the duct. This gives spatial concentrations and velocities that can be used to determine the mass emissions. As a result, multiple measurements are needed.

For any given emission rate, volumetric sampling rate, and sample time, there is a possible random error[42] for any M5 measurement, and this will be true regardless of whether the M5 measurement is being used to calibrate a PM CEMS or is being used as the means of demonstrating compliance. For any given sample rate and sample time, the random error will increase as a percent of the measurement at lower concentrations. That random error can be reduced by increasing the PM sample size, which can be achieved by increasing the volumetric sampling rate, or increasing the time to take the sample. For low emission rates it will take more time to accumulate a sample large enough to offer a reliable measurement (large enough to have a low random error of measurement). Importantly, even when stack measurements are being used in lieu of CEMS for demonstrating compliance with a PM limit, at low emissions levels it is necessary to take longer samples or risk higher random error. There are also procedural approaches, some discussed in Method 5I, that can be used at lower PM emission rates. So, this issue of random error at low levels is not limited to PM CEMS but applies to M5 measurements at low levels in general.

EPA explained that a concern with use of PM CEMS is their ability to demonstrate low emissions levels while maintaining adequately low random errors. EPA's *PM CEMS Random*

[41] Nearly every CEMS or process analyzer does this, inferring concentration from other, more easily measurable qualities, such as light absorption, UV fluorescence, chemiluminescence, etc. Optical scattering methods are impacted both by stratification in the duct as well as by the optical characteristics of the PM (especially particle size distribution). So, calibration is especially important.

[42] This is the term used by EPA. In effect, this is how variation in measurements compare to the average of the measurements at a given concentration, and this will be a higher percentage at lower concentrations than at higher concentrations.

Error Contribution by Emission Limit memo[43] presents an analysis that indicates that if facilities maintain lower emission levels, developing the calibration for a PM CEMS will require longer stack sampling times to ensure sufficiently low random error. The concern is really about how to perform a calibration of the CEMS with M5 as opposed to the concern about the absolute sensitivity of the instruments or accuracy if correctly calibrated. While the context of the discussion in the proposal is regarding PM CEMS, the issue of random error for M5 exists to some degree whether M5 stack sampling is the method of demonstrating compliance, or if it is being compared to the response of a PM CEMS for the purpose of calibration. The main difference is that, for PM CEMS, M5 measurements are used to develop a calibration curve.

A calibration curve is developed against a number of M5 measurements. Lower emission levels require higher-volume M5 samples to collect a sample for a given random error and therefore longer test periods (or, alternatively, higher volume flow rates) and perhaps higher testing costs. Longer test periods present two problems. First, operating changes more likely to happen over a longer test period could adversely impact how representative a measurement is. Second, longer sample periods also entail more cost. EPA has indicated in the proposal a three-hour sample period as being reasonable,[44] but in its memo it examines longer sample times up to 8 hours. EPA's analysis shows calculations of random error at a range of emission limits and sample times. It shows that, at an emission limit of 0.006 lb/MMBtu (estimated to be equivalent to 4.4 mg/dscm), a sampling time of 1 hour would result in a level of uncertainty at the target compliance level of 6.8% and an average random error over the response range of 27.3% with 20 days of stack testing to perform the calibration. In EPA's memo, there is no discussion of the possible use of higher-volume sampling systems or other techniques to improve sample quality, which can be used to increase the amount of material sampled in a given period of time and would reduce the time needed to conduct tests. EPA also does not explain whether longer sampling times are similarly problematic for stack samples at low concentrations as it suggests they may be for PM CEMS that use stack samples for their calibration.[45]

EPA also does not evaluate Quantitative Aerosol Generators (QAGs) in their memo or elsewhere, which can take a sample of PM collected from the baghouse or ESP hopper and readmit it to the exhaust stream. QAGs are devices that can generate an aerosol to develop different PM rates for the purpose of developing a calibration curve. Thus, QAGs offer another possible means to calibrate the instruments and address these concerns.

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[43] EPA, PM CEMS Random Error Contribution by Emission Limit, EPA-HQ-OAR-2018-0794-5829 (Mar. 2023).

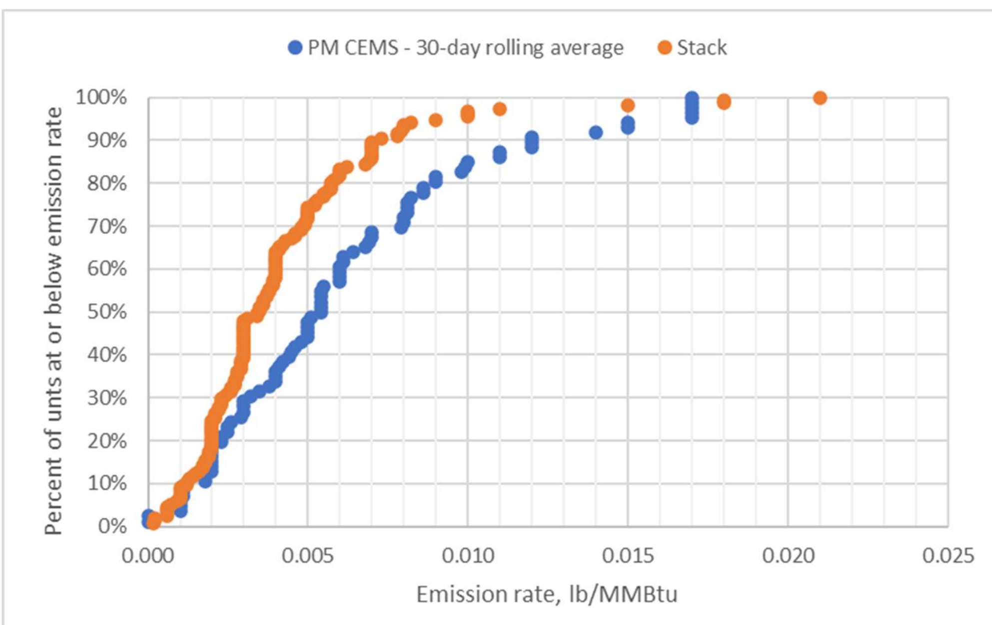
[44] Federal Register / Vol. 88, No. 78 / Monday, April 24, 2023 / Proposed Rules, pg. 24,874.

[45] It is also worth noting that periodic Method 30B measurements for low mercury emitters that do not have a Hg CEMS will often require days.

3. PM CEMS and Method 5 are being used to demonstrate compliance at much lower emission rates than EPA seems to indicate could be done reliably.

In practice, PM CEMS (and stack measurements as well) are being used to demonstrate compliance, and report emissions, at levels well below the proposed and alternative, more stringent fPM standards. As demonstrated in Figure 4, which was developed by ATP using data from NRDC a number of years ago, PM CEMS were more likely than not to be used on facilities reporting emissions rates in the two lowest-emitting deciles, at about 0.0020 lb/MMBtu or lower. Moreover, the NRDC data as well as the data used by EPA in developing the rule also suggest that the long sampling times at low emission levels are not proving to be problematic for facilities that demonstrate compliance with stack sampling. Figure 12 is developed from data in EPA's Technology Review and demonstrates that about 10% of the units with PM CEMS reported emissions levels of about 0.0015 lb/MMBtu or below (similar percentage for stack sampling), over 20% of the units with PM CEMS reported emissions levels of 0.0025 lb/MMBtu or below (about 30% for stack sampling), and nearly half of the units with PM CEMS reported emissions levels of 0.005 lb/MMBtu or below (70% for stack sampling). Therefore, the data used by EPA show that PM CEMS are already being used to report emissions levels well below EPA's proposed and alternative fPM standards. Moreover, EPA's data also support the fact that the long sampling times at low emission levels are not proving to be problematic for facilities that demonstrate compliance with stack sampling.

Figure 12. Percent of units with a measurement method (PM CEMS or stack sampling) with baseline fPM emissions at or below a particular emission rate[46]



[46] Developed from Appendix C data from 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category.

4. There appear to be a number of possible solutions to the issues EPA has raised regarding random error.

The issue of random error may be addressed in a number of ways that are discussed here, and EPA's analysis has shown that rates of 0.006 lb/MMBtu and below can be demonstrated within acceptable random error ranges. There are multiple options for increasing the sample size of a M5 sample to reduce random error, including increasing volume flow rate, or increasing sample period. There are also methods that can be used to improve the reliability of PM measurements at low levels, such as those addressed in Method 5I. In this proposal, EPA has only looked at one of those options: sample period. Moreover, PM CEMS and stack samples are already both being used to report emissions down to very low levels, and EPA has relied upon these measurements in formulating the proposed rule.

C. Hg emissions standards

EPA proposes to revise the emission limit for low-rank (specifically, lignite[47]) coals only. EPA in 2021 solicited information related to Hg emissions from certain lignite-fired coal units. EPA did not collect information on units burning other coals.

The 2021 ATP report identified several Hg control technology improvements since the 2012 MATS rule that qualify as "developments" that could necessitate lower emission limits. These developments include more-advanced activated carbons that provide higher capture at lower injection rates and carbons that are tolerant of flue gas species such as SO_3 and NO_2. With these advancements, high Hg capture (over 90%) is possible under virtually any range of circumstances. The 2021 ATP report also discussed advances in fuel additives, scrubber operation, scrubber systems like the Gore technology, and scrubber additives (activated carbon and other additives). These developments clearly indicate a need to review Hg emissions standards for all coal-fired units.

1. Lignite-fired units are capable of achieving the proposed Hg emission standard

Lignite coal generally has higher Hg content than other coals, and the 2012 MATS rule established a higher Hg emission limit for lignite units than for non-lignite units. EPA has proposed making the lignite limit consistent with the current limit for non-lignite units. The data in EPA's analysis demonstrated that emissions capture of between about 76% and 92% would be necessary for lignite units to meet the proposed limit of 1.2 lb/TBtu.[48] This is well within the capabilities of

[47] For purposes of this analysis, the terms "lignite" and "low-rank" are used interchangeably and refer to the same set of units.

[48] EPA, 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, EPA-HQ-OAR-2018-0794-5789, Tbl. 11 (Apr. 2023).

these facilities. Every one of these facilities is equipped with some form of FGD (scrubber)[49] and/or a baghouse. They are all equipped with ACI. There are no lignite facilities with an ESP as the sole air pollution control device, which is the most challenging situation for Hg removal. As a result, each of these lignite facilities is capable of well over 90% Hg capture with these other pollution control devices used in combination with the existing ACI system.

For most lignite units, EPA collected information on whether or not activated carbon was injected—in some cases identifying the brand of the carbon, in some cases whether or not it was halogenated—and collected data relating to treatment rate.[50] In the case of the Coal Creek, Coyote and Limestone plants, no information was collected. EPA calculated the cost-effectiveness of Hg reductions for a model plant (800 MW lignite unit) at two different treatment rates – one presumed to produce an Hg emission rate of 4.0 lb/TBtu and the other an emission rate of 1.2 lb/TBtu, based upon data from the "beyond-the-floor memo from the 2012 MATS Final Rule."[51] Notably, EPA did not perform facility-specific calculations.

As will be shown, ATP has determined that lignite units, in addition to being capable of reducing emissions to the current Hg standard for non-lignite units of 1.2 lb/TBtu, can reduce emissions further.

2. Non-lignite units are capable of achieving lower Hg emission levels than currently required.

EPA did not collect data from non-lignite units, and stated in the proposed rule that: [52]

> *Without knowing the type of sorbent being injected or the rate of the sorbent injection, it is difficult to determine whether additional emission reductions could be achieved in a cost-effective manner.*

EPA does have information on the type of sorbent used (for example, "halogenated activated carbon") for each unit in the Air Markets Program Data that is submitted each quarter but does not have information on the treatment rate or the manufacturer. As previously noted, EPA performed the cost-effectiveness calculation for lignite units based upon a model plant and data from the 2012 rule, without identifying a specific carbon manufacturer. EPA did not perform facility-specific calculations. It also did not account for improvements in activated carbon since 2012.

It is not necessary to know the type of sorbent being injected or the rate of sorbent injection at each individual unit to determine whether additional emission reductions could be achieved in a cost-effective manner. As described in the 2021 and 2023 ATP reports, ATP did in fact make

[49] Sometimes in combination with an ESP

[50] EPA, 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, EPA-HQ-OAR-2018-0794-5789, Tbl. 9.

[51] Federal Register / Vol. 88, No. 78 / Monday, April 24, 2023, pg. 24,881.

[52] Ibid., pg. 24,879.

estimates of the incremental cost of mercury control to lower emission rates for both lignite and non-lignite units. Today there is far more data available on non-lignite units to evaluate the cost of complying with a lower Hg emission level than there was when EPA evaluated the cost of complying with the emission levels of the 2012 MATS regulation. EPA has years of Hg emissions data on every unit, nearly all using Hg CEMS, along with coal type and air pollution control configuration as well as the type of carbon being used. Moreover, there is ample published material on the cost of Hg control at different capture levels using ACI as well as other approaches, as described in the 2021 ATP report and in conference proceedings, such as the 2012, 2014, 2016, 2018 and subsequent AWMA Power Plant Pollution Control "MEGA" symposiums. Data are publicly available for control costs at different capture rates and different configurations (coal type, air pollution control configuration, etc.). The only information needed to determine achievable Hg emission rates is the input Hg content and the potential capture percentages. So, determining the additional control needed and the cost is straightforward and is what was done in the 2021 and 2023 ATP reports. In effect, this is what EPA did for lignite units, but for a model plant using generic (not unit specific) treatment rates.

EPA commonly makes unit-specific cost estimates based upon general facility data. In prior rulemakings, EPA has made estimates of controlling emissions of NO_x, SO_2, and other pollutants without knowing more than the type of fuel, the equipment that is installed, the capacity, and other general characteristics of the facility. Details about scrubber or SCR design (for example, liquid to gas ratio, stoichiometry, catalyst loading, etc.) were not used by EPA in any of those prior rulemakings.[53] EPA has consistently made cost estimates for control of pollution by ascertaining what technologies are capable of and at what cost, and what controls are installed at existing facilities. All of the air pollution control cost algorithms EPA uses for IPM, whether for Hg, NO_x, SO_2, PM, HCl, etc. have, as primary inputs, general facility characteristics. Detailed equipment or reagent/sorbent characteristics are typically not necessary.

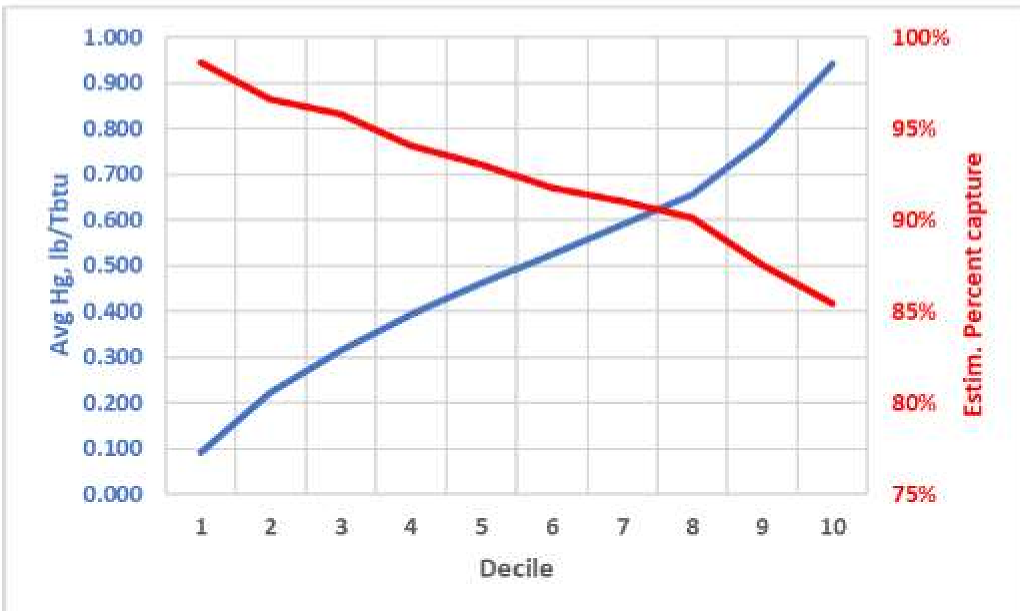
For non-lignite units, EPA could have made a similar calculation as the one made for lignite units on a model plant, but for those non-lignite units equipped with solely an ESP and ACI, which is the most difficult application of Hg control. EPA could have also updated their ACI cost and treatment rate algorithms using up-to-date data that are available in the public domain. Or, they could have done what ATP did, use facility-specific data and publicly available ACI performance curves to develop facility-specific cost estimates and a resulting fleetwide estimate of costs at different control levels.

[53] These may be calculated using algorithms, but the calculations are based upon general facility characteristics, just as activated carbon injection rates can be estimated from general facility characteristics.

a. Data demonstrate that lower Hg emissions levels are being achieved at non-lignite units at reasonable costs.

Figure 13 appears in ATP's 2021 report. It shows the reported average Hg emission rate and estimated Hg capture rate from coal Hg content for not-low-rank coals. Coal Hg content is developed from EPA's IPM documentation. This includes scrubbed units as well as units with baghouses, and it shows that 80% of the units (units in the top 8 deciles) were achieving 90% Hg emissions capture or better and were achieving Hg emission rates of 0.65 lb/TBtu or lower.

Figure 13. Average Hg concentration and estimated percent capture by decile for not-low-rank virgin coal[54]



The most challenging applications are those where there is only an ESP for fPM control and no scrubber. These applications are typically reliant upon ACI for Hg control because they do not receive the degree of intrinsic Hg capture that scrubbed units or units with baghouses experience. For ESP-equipped units, carbon injection rate is higher than for baghouse-equipped units for any given rate. As described in the 2021 ATP report, ACI is a "dial up" technology where the rate of removal can be increased or decreased as desired by changing the activated carbon injection rate. Absent another motivation, facilities will often control only to the degree that they need to in order to maintain under the emission standard. Greater than 90% capture with ACI has been demonstrated on a wide range of coals and under a wide range of conditions.

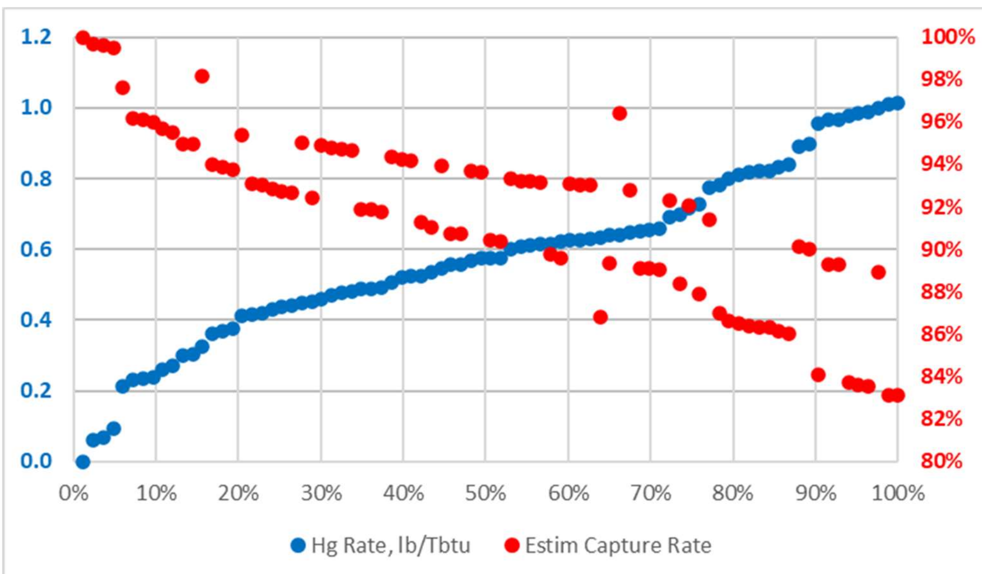
Figure 14 shows the emission rate and estimated capture efficiency for non-lignite coal units with only an ESP (no FF or scrubber) and ACI. As shown, over 50% achieved at or below 0.6 lb/TBtu and over 90% capture even though the MATS limit is 1.2 lb/TBtu. Some units are

[54] ATP 2021 report

estimated to be achieving over 95% capture. In fact, it is at about 0.4 lb/TBtu or about 95% capture where data start to fall off, with about 20% of units achieving lower emissions and higher capture efficiency. Clearly, achieving an emission rate at or below half of the MATS emission standard was feasible and cost-reasonable for these units.

About 10% of the units were achieving emission rates at or above 0.80 lb/TBtu. Given that the facilities represented in Figure 14 were using ACI and in many instances could reduce their carbon injection rate to maintain just below the emission standard, it is actually surprising that only 10% controlled to rates at or above 0.80 lb/TBtu. Some of these units were also subject to state regulations that were more stringent than the MATS limit. But, it is clear from this data that controlling Hg emissions to emission rates well below the MATS limit is achievable in a cost-effective manner on unscrubbed units with ESPs because fully 60% of the units reduced emissions to half the MATS level or less.

Figure 14. Hg emission rate (lb/TBtu) and estimated capture efficiency for not-low-rank coal, unscrubbed units, with only an ESP and ACI[55]



3. Estimating the cost to control Hg to lower emission levels

The Hg algorithms that EPA uses for IPM are not suitable to evaluate the incremental cost of controlling Hg to lower emission rates. EPA's IPM algorithms for Hg capture were originally developed by Sargent & Lundy in 2011 and last updated in 2017.[56] These algorithms estimate control cost using general facility data. In both cases (2011 and 2017) these algorithms assume

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[55] ATP 2021 report

[56] Sargent & Lundy, "IPM Model – Revisions to Cost and Performance for APC Technologies - Mercury Control Cost Development Methodology – Final", March 2011.

Sargent & Lundy, "IPM Model – Updates to Cost and Performance for APC Technologies - Mercury Control Cost Development Methodology – Final", January 2017.

only a single Hg capture efficiency (80%) and a specific injection rate that is determined by whether there is an ESP or a baghouse, or if the unit is scrubbed. EPA's own data show over 90% capture for the majority of unscrubbed, ESP-equipped units, which indicates that the algorithms are not up to date. Since only one injection rate is used in the algorithm for a given air pollution control configuration, the algorithms are not useful for examining cost of compliance at different capture efficiencies. The treatment rate calculation, being unchanged between 2011 and 2017, indicates that improvements in sorbents that have permitted higher Hg capture levels at lower treatment rates for any given application that were developed since 2011 are not incorporated into the algorithm. For these reasons, it is necessary to use other approaches to estimate the cost of controlling Hg to lower emission levels, and this is what EPA did for lignite-fired facilities, albeit, using a model unit.

It is possible to estimate the incremental cost based upon published data on the performance and cost of activated carbon. This is done with the understanding that the facility owner has many choices in how they can control Hg and may choose another approach to reduce their emissions if it is less expensive. For example, they may add a fuel additive rather than increasing carbon injection rate. To perform unit-specific calculations, ATP developed a methodology in 2021 that was discussed in the 2021 report and further used in the 2023 addendum to that report. Algorithms for ACI treatment rates and cost (on a mill/kWhr basis) as a function of capture efficiency were developed, depending upon the type of PM control device (ESP or baghouse). In this report, this methodology is built upon and utilized to provide an updated cost estimate using the database of units considered in Appendix C of the 2023 Technology Review, with facility configurations from NEEDS. Costs are updated to 2019 dollars. ATP assumed a control level of 20% below the emission standard. The following are some assumptions when calculating variable operation and maintenance costs (VOM) using the algorithms described in the 2021 ATP report:

Scrubbed units

- The VOM increase in mill/kWhr due to a lower emission standard is based upon the incremental Hg reduction by comparing the relative capture efficiency now (based upon reported Hg emission rates and estimated coal mercury) and after applying a new Hg standard. For example, moving from 80% capture to 90% capture would be an incremental capture rate of 50%.
- If a new BH is added to comply with a more stringent fPM emission standard, no incremental VOM is assumed because Hg capture will be improved significantly simply by adding the baghouse.

Unscrubbed units

- Initial VOM is estimated from an algorithm using the current capture efficiency (based upon reported Hg emission rates and estimated coal Hg).
- Final VOM is estimated from an algorithm using the final capture efficiency (based upon reported Hg emission rates and estimated coal Hg).

- Incremental VOM in mill/kWhr is determined by the difference.
- A BH may be added as a result of an fPM limit or because a unit without an existing BH needs a total capture efficiency that is above 95% capture. When a BH would be needed to meet the fPM limit, the cost of the BH is attributed to the fPM requirement and not the Hg requirement.
- In situations where a BH is added to a facility with an ESP as a result of a more stringent PM emission standard, the final VOM will often be less than the initial VOM because the ACI system is much more effective when a BH is used.

Annual incremental VOM is calculated from the above incremental VOM in mill/kWhr using a capacity factor of 50%.

If ACI is not installed and additional Hg capture is needed, it is assumed that ACI is added at a capital cost of $15/kW. If an ACI system is installed and either VOM increases greater than 50% or a new BH is installed as a result of a new fPM standard, then a capital cost of $5/kW is assumed to address any modifications to the ACI system.

Capital recovery factor is 11% of initial capital cost and fixed O&M (FOM) on a new ACI system is assumed to be 1% of initial capital cost.

ATP is updating the estimated *incremental* cost of controlling Hg to lower emissions versus existing emission levels for the fleet of coal units identified in EPA's 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, Appendix B and C.

The method was first used to examine the economic impact of the proposed rule, with fPM emissions at 0.01 lb/MMBtu and lignite units meeting an Hg emission limit of 1.2 lb/TBtu. The model found a total annualized cost of $4.4 million for all 23 lignite units, an estimated $/lb of $6,810/lb of Hg,[57] and $0.0925/MWhr. The cost effectiveness in $/lb of Hg is in a similar range as that estimated by EPA ($8,703/lb) for the 800 MW model plant (the average lignite plant is 493 MW in size).[58] EPA assumed that the activated carbon rate at the proposed emission standard would be 5.0 lb/MMacf.

The emission standard assumptions modeled in today's report that examines the proposed rule and the possibility of lower emission rates are shown in Table 5 and the results for total fleetwide costs for lignite (low-rank) units are shown in Figure 15. As shown, for any given set of Hg emission rates, the PM emission rate has a large impact on the cost of Hg compliance because

[57] The model calculates the mass of Hg reduction based upon the difference between the actual emission rate in the NRDC database and the lower emission standard, the heat rate and capacity in the NEEDS database, and an assumed 50% capacity factor.

[58] According to the Technical Review, EPA stated that the Oak Grove units were injecting less than 0.50 lb/MMacf while achieving 82.6%-86.2% capture efficiency. Nevertheless, EPA assumed that the injection rate for the model plant in calculating cost would be increased from 2.5-5.0 lb/MMacf, which is in increase in treatment rate of 2.5 lb/MMacf – or an increase that is five times the current treatment rate at Oak Grove. EPA's estimates are therefore very conservative from the perspective of carbon treatment rate.

baghouse installations for fPM control will reduce the cost of Hg compliance by both reducing treatment rate costs and because baghouses that might otherwise be needed for Hg control are installed for fPM control. As expected, as Hg emissions rates become less stringent, for any given fPM requirement, the costs decrease.

Table 5. Emission standard assumptions for Hg cost calculations

PM, lb/MMBtu	0.006	0.004	0.0024	0.006	0.004	0.0024
Hg, Not Lignite or not-low-rank (NLR), lb/Tbtu	0.15	0.15	0.15	0.5	0.5	0.5
Hg, Lignite or low rank (LR), lb/Tbtu	0.5	0.5	0.5	1.2	1.2	1.2

Under the proposed rule, the estimated incremental impact to generation cost of the proposed 1.2 lb/TBtu Hg standard for lignite units is $0.17/MWhr. Figure 16 shows the result of cost effectiveness and impact to generation calculations for low-rank coals. As shown, at an fPM emission rate of 0.006 lb/MMBtu and a Hg emission rate of 0.5 lb/TBtu, the impact to generation cost is $1.33/MWhr and the impact to generation at a Hg emission rate of 1.2 lb/TBtu is $0.11/MWhr. At an fPM emission rate of 0.0024 lb/MMBtu and a Hg emission rate of 0.5 lb/TBtu, the impact to generation cost is $0.24/MWhr and the impact to generation at a Hg emission rate of 1.2 lb/TBtu is $0.03/MWhr.

Figure 15. Total fleetwide Hg annualized incremental costs as a function of fPM and low-rank (LR) or lignite Hg rate

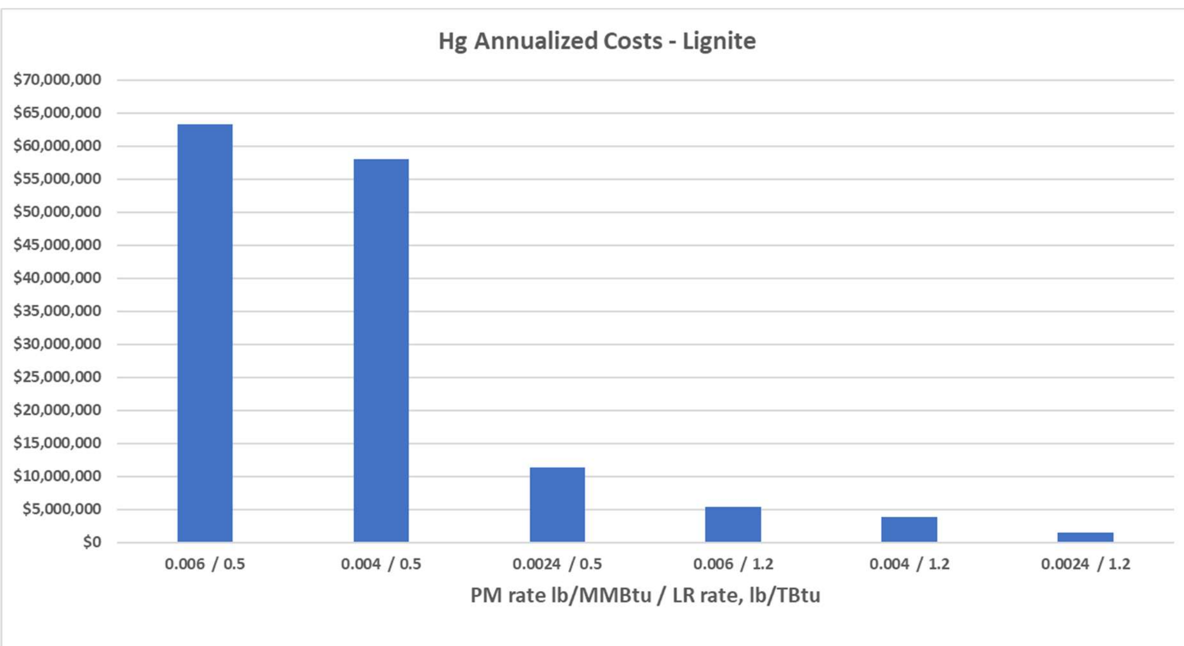


Figure 16. Hg control costs, $/lb costs and $/MWhr, as a function of fPM rate and low-rank (LR) or lignite Hg rate

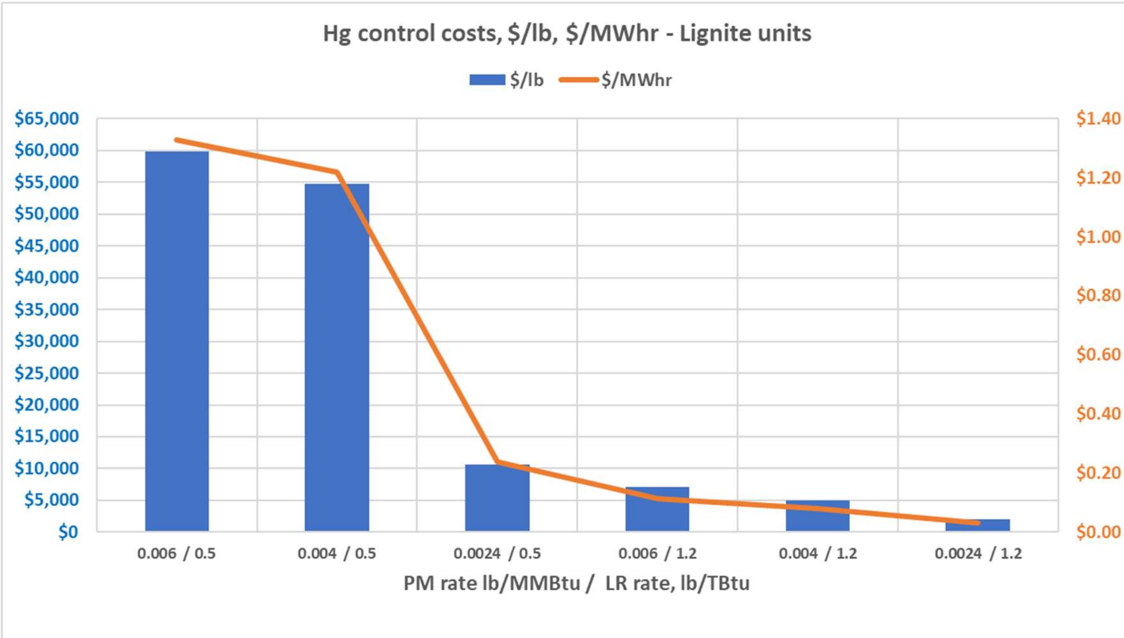


Figure 17 shows the incremental fleetwide control costs for not-low-rank units at different fPM emission rates and Hg emission rates. As shown, for any given set of Hg emission rates, the PM emission rate has a large impact on the cost of Hg compliance because baghouse installations for fPM control will reduce the cost of Hg compliance by both reducing treatment rate costs and because baghouses that might otherwise be needed for Hg control are installed for fPM control. As expected, as Hg emissions rates become less stringent, for any given fPM requirement, the costs decrease.

At the proposed fPM emission rate, the estimated incremental impact to generation cost of a Hg standard of 0.50 lb/TBtu for non-low-rank coals is $0.12/MWhr. Figure 18 shows the result of cost effectiveness and impact to generation calculations for not-low-rank coals. As shown, at an fPM emission rate of 0.006 lb/MMBtu and at a Hg emission rate of 0.5 lb/TBtu, the impact to generation cost is $0.10/MWhr – less than the estimated impact to generation of the proposed rule on lignite units assuming prior compliance with a more stringent fPM limit of 0.006 lb/MMBtu – and the impact to generation at a Hg emission rate of 0.15 lb/TBtu is $0.81/MWhr. So, controlling Hg to lower emission rate standards can be achieved at lower impacts to generation cost for non low-rank units than for lignite units at any given fPM standard. At an fPM emission rate of 0.0024 lb/MMBtu and a Hg emission rate of 0.5 lb/TBtu, the impact to generation cost is $0.03/MWhr and the impact to generation at a Hg emission rate of 0.15 lb/TBtu is $0.31/MWhr.

Figure 17. Total fleetwide Hg annualized incremental costs as a function of fPM rate and not-low-rank (NLR) Hg rate

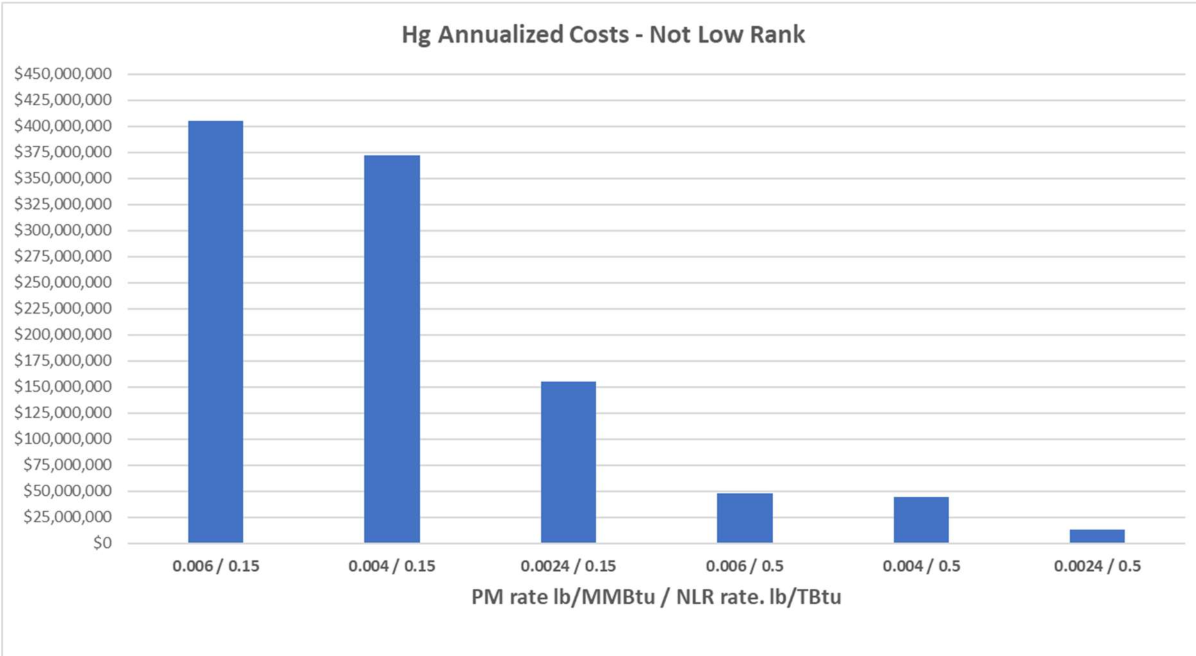
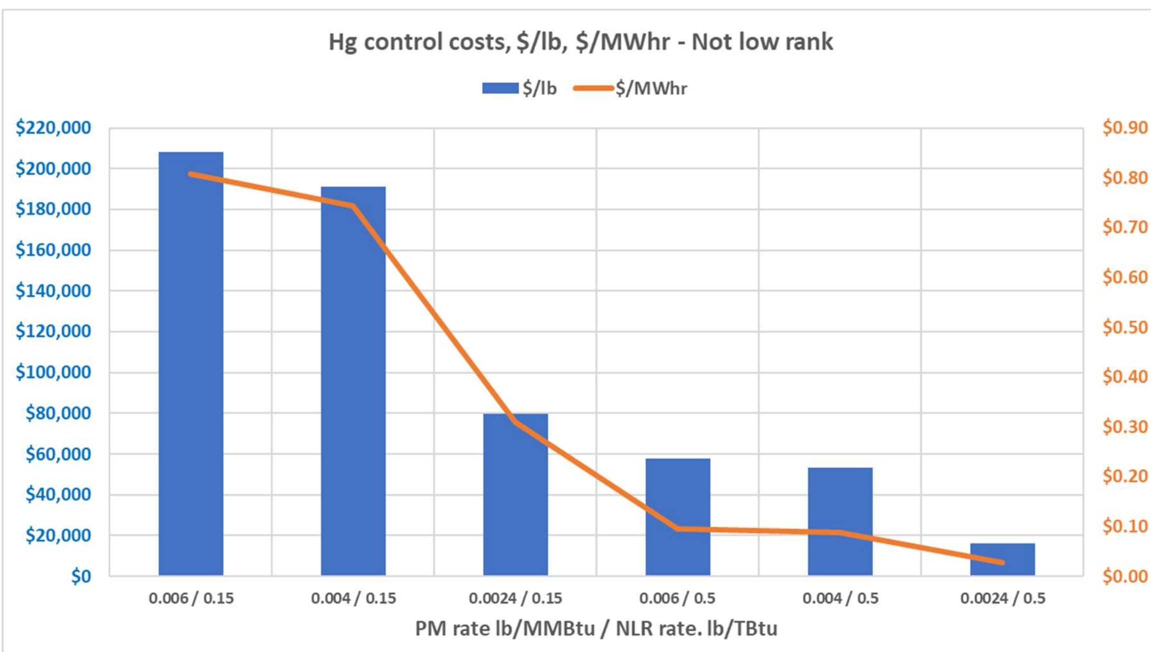


Figure 18. Hg control costs, $/lb costs and $/MWhr, as a function of fPM rate and not-low-rank (NLR) Hg rate



D. Acid gas emission standards

In its proposal,[59] EPA states, "In summary, the EPA has not identified any new control technologies or any improvements to existing acid gas controls that would result in additional cost-effective acid gas HAP emission reductions from coal-fired EGUs." This is a different conclusion than that in ATP's 2022 report that determined that there were improvements in HCl control technologies since the 2012 MATS rule. This is also inconsistent with EPA's own treatment rate algorithms for calculating the costs of controlling HCl using DSI, which changed between August 2010 and April 2017.[60] ATP's 2022 report provides data that demonstrate that performance is even better than shown in the 2017 Sargent & Lundy memo.

EPA plotted data that it collected on SO_2 and HCl emissions in Figure 19 (Figure 3 in EPA's memo[61]), with the description as follows:

> *The EPA reviewed compliance data for SO_2 and/or HCl as shown in Figure 3 below – showing EGUs with highest SO_2 emissions in 2021 to those with the lowest SO_2 emissions in 2021. Approximately two-thirds of coal-fired EGUs have demonstrated compliance with the alternative SO_2 emission standard rather than the HCl emission limit. Those units are shown on the plot in Figure 3 as the blue data points below the red line indicating the MATS SO_2 emission limit of 0.20 lb/MMBtu. About one-third of EGUs have demonstrated compliance with the primary acid gas emission limit for HCl. And some sources have reported emissions data that demonstrates compliance with either of the standards. Emission rates for HCl are shown in Figure 3 as green data points for EGUs that utilize some sort of acid gas control system – which would be a wet FGD scrubber, a dry scrubber (an SDA), reagent injection or DSI. The purple datapoints on the plot in Figure 3 represent HCl emission rates for units that do not have a wet FGD scrubber or an SDA and do not utilize either reagent injection or DSI. All of those EGUs with no acid gas controls are units that were firing subbituminous coal and were able to demonstrate compliance with the HCl emission standard due to the low natural chlorine content and high alkalinity of most subbituminous coals.*

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[59] Federal Register / Vol. 88, No. 78 / Monday, April 24, 2023, pg. 24,883.

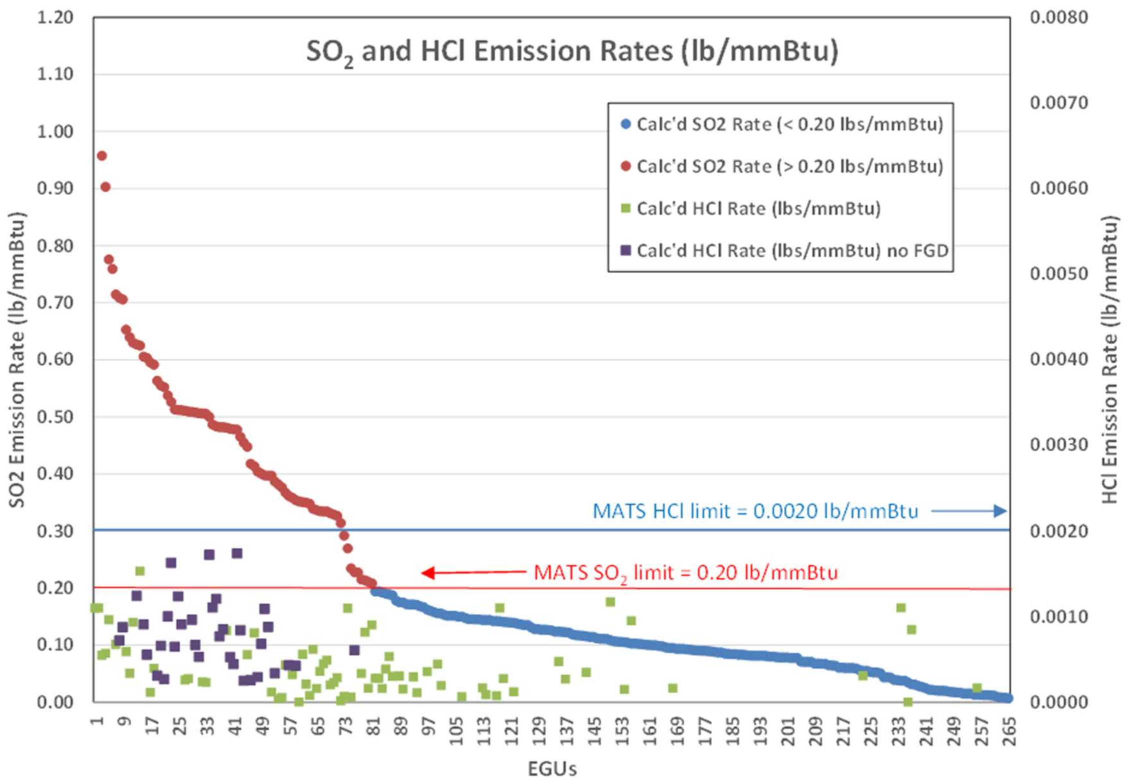
[60] Sargent & Lundy, "IPM Model – Revisions to Cost and Performance for APC Technologies, Dry Sorbent Injection Cost Development Methodology – FINAL", August 2010.

Sargent & Lundy, "IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO2/HCl Control Cost Development Methodology – Final", April 2017.

[61] EPA, 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, EPA-HQ-OAR-2018-0794-5789 (Apr. 2023).

For facilities with controls, EPA further plotted the HCl emissions in Figure 20 (Figure 4 in EPA's memo[62]). (Note that the title of the graph contains errors, as these emissions rates are for coal-fired EGUs (not liquid oil-fired EGUs) that are equipped with some type of acid gas controls (not just FGD).) Notably, EPA did not make a distinction between DSI-equipped units with baghouses and DSI-equipped units with ESPs on this plot, although they acknowledged that there were important differences in the text of the document.

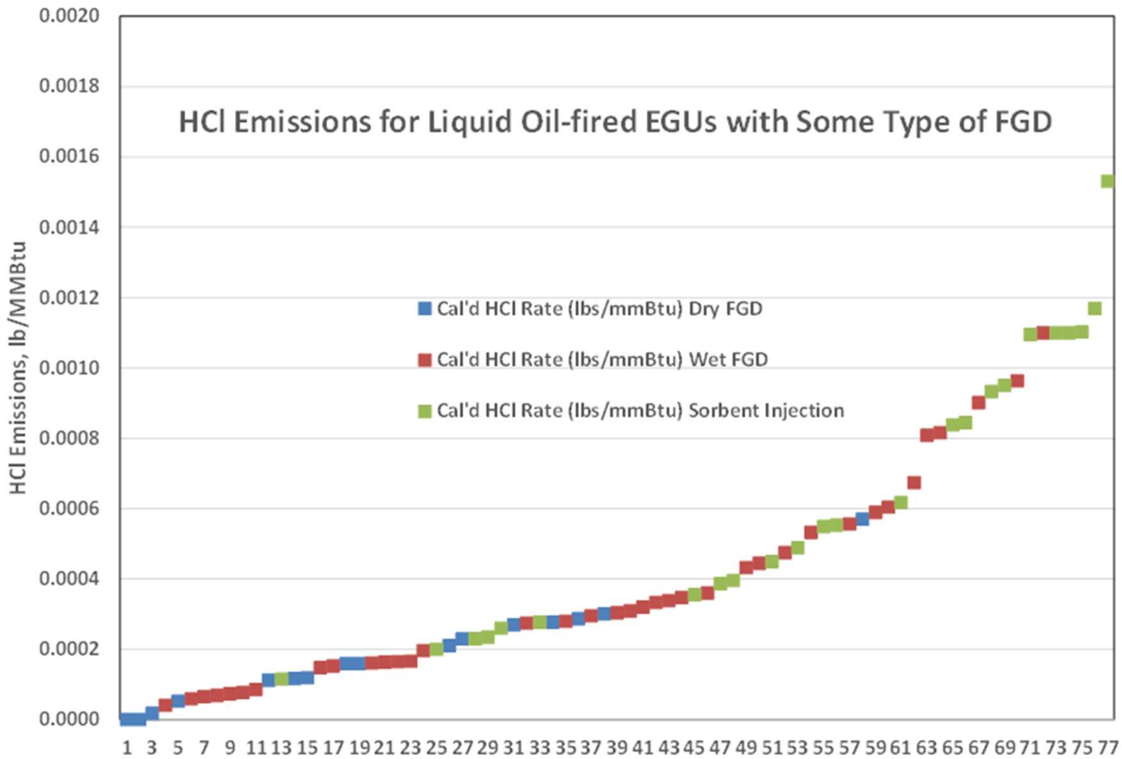
Figure 19. SO_2 AND HCL EMISSION RATES FOR COAL-FIRED EGUS OPERATING IN 2021[63]



[62] EPA, 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, EPA-HQ-OAR-2018-0794-5789 (Apr. 2023).

[63] Reproduced from EPA, 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, EPA-HQ-OAR-2018-0794-5789 (Apr. 2023).

Figure 20. HCL EMISSION RATES FOR COAL-FIRED EGUS WITH AND WITHOUT ACID GAS CONTROLS THAT WERE OPERATING IN 2021[64]



In the 2022 report, ATP also examined the relationship between controlled SO_2 emissions, HCl emissions, and technology type. Table 6 shows a comparison of ATP's findings and those shown in Figure 19 and Figure 20.

[64] Reproduced from EPA, 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, EPA-HQ-OAR-2018-0794-5789 (Apr. 2023). Note that the title of the graph contains an error, as these emissions rates are for coal-fired EGUs.

Table 6. Comparison of ATP and EPA findings

	ATP 2022	EPA
Wet FGD	For wet FGD-equipped units that reported HCl emissions, there was a significant correlation between HCl emissions and SO_2 emissions, with only four of 25 units having HCl emission rates greater than 0.0006 lb HCl/MMBtu.	6 units with greater than 0.0006 lb/MMBtu and 31 units with emissions below 0.0006 lb/MMBtu
Dry FGD	For dry FGD-equipped units (only one in the NRDC database), HCl was around 0.0001 lb/MMBtu and SO_2 was about 0.06 lb/MMBtu. It is not surprising that HCl would be captured effectively in the alkaline-rich filter cake in the baghouse of a dry FGD system.	All units with HCl emissions below 0.0006 lb/MMBtu
DSI	For DSI-equipped units, those with baghouses were consistently below 0.0006 lb HCl/MMBtu and below 0.4 lb SO_2/MMBtu. All DSI-equipped units (whether with an ESP or baghouse) with SO_2 below 0.4 lb/MMBtu had HCl emissions below 0.0006 lb/MMBtu. For DSI-equipped units with ESPs with SO_2 greater than 0.4 lb/MMBtu, SO_2 was in a range of about 0.52-0.62 lb/MMBtu and HCl ranging about 0.00058-0.0011 lb/MMBtu.	11 units with HCl emissions between 0.00061 and 0.00135 lb/MMBtu and 13 units with HCl emissions below 0.0006 lb/MMBtu. Importantly, EPA acknowledges that DSI-equipped units with baghouses have lower HCl emissions than those with ESPs, but does not quantify the difference.
No add-on acid gas control	SO_2 versus HCl analysis shows significant amount of scatter for ESP and baghouse-equipped units, but much less scatter for ESP + baghouse-equipped units	No analysis by technology. All technologies plotted together show high scatter.

As shown, for scrubbed units both ATP and EPA had similar findings. For DSI, EPA acknowledges that PM control has an impact, although EPA does not state the impact in quantitative terms. It is not surprising that PM control technology has a significant impact on HCl emissions rates. For a baghouse-equipped unit, the sorbent has much more intimate contact with the exhaust gas as the gas passes through the filter cake. This is a phenomenon that is widely known to occur for ACI-equipped units. In fact, EPA's DSI algorithms developed by Sargent & Lundy also acknowledge the significant difference between baghouse-equipped and ESP-equipped units for DSI.

Some of the advances in DSI technology that have occurred between 2012 and today, and are documented in ATP's 2022 report, include:

- More-advanced sorbents
- More-advanced sorbent injection systems.

EPA states in the 2023 Technology Review:

It is not clear that improvements in a wet or dry FGD scrubber would result in additional HCl emission reductions since HCl emissions are already much easier to control than SO_2 emissions. The EPA does not have information on the injection rates for DSI systems; so, we cannot assess whether increased sorbent injection rates would result in additional HCl emission reductions. Units using DSI in combination with an ESP would almost certainly see improved performance if they were to replace the ESP with a FF. However, that small incremental reduction in HCl emissions would come at a high cost and would certainly not be a cost-effective option.

ATP reaches a different conclusion based upon the findings of the 2022 report and EPA's data, as will be described below for facilities with different acid gas control configurations (if any).

a. Dry FGD-equipped units

Dry FGD systems already provide HCl emissions that are below 0.0006 lb/MMBtu. They are, on average, the best controlled units from the perspective of HCl. While there are opportunities to reduce HCl further for these units, none would need to make any changes if a new standard of 0.0006 lb/MMBtu were established.

b. Wet FGD-equipped units

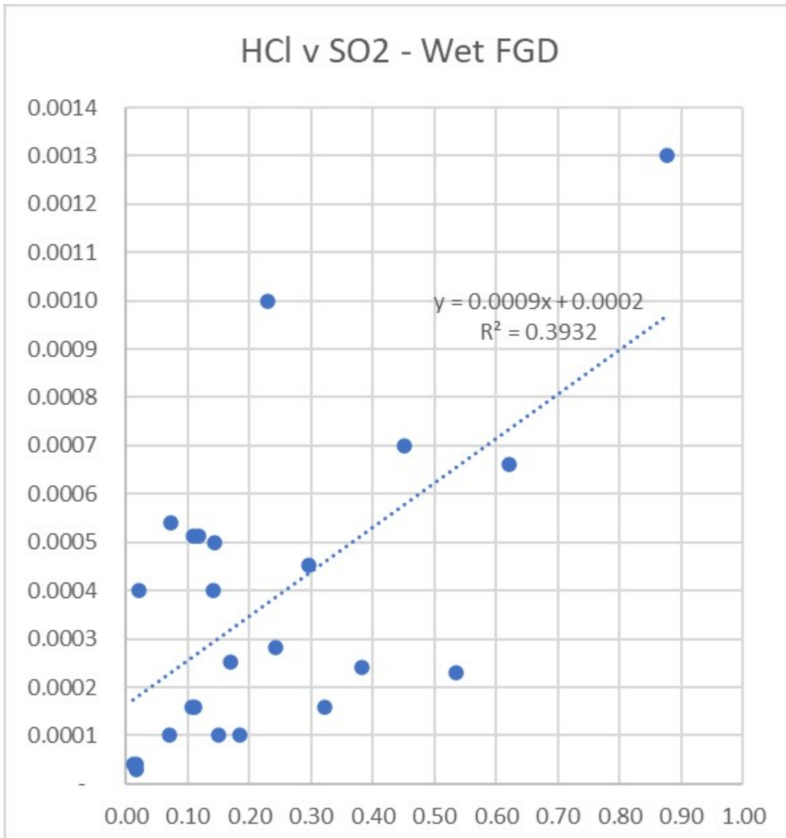
As described in the 2022 ATP report, a large portion of the units with wet FGDs operating in 2011 experienced substantial reductions in SO_2 emission rates by 2019. This clearly demonstrates that wet FGD upgrades were being deployed at a significant rate during that period. That report also demonstrated that the upgrades were less expensive than EPA had assumed in the development of the 2012 MATS rule.

With regard to wet FGD-equipped units, ATP's 2022 report showed a significant correlation between HCl and SO_2 emissions, as shown in Figure 21, which is from that report. This is consistent with the premise of the 2012 MATS rule that lower SO_2 rates on scrubbed units tend to be associated with lower HCl rates. As shown, for SO_2 emissions below 0.20 lb/MMBtu, there are no units with HCl emissions greater than 0.0006 lb/MMBtu (less than a third of the current standard). Only four of 25 wet FGD-equipped units have HCl emission rates greater than 0.0006 lb/MMBtu.[65] Therefore, those units that are complying with the emission standard by maintaining SO_2 below 0.20 lb/MMBtu are likely maintaining HCl emissions below 0.0006 lb/MMBtu and well below the current HCl standard. But, for those units that have SO_2 emissions greater than 0.20 lb/MMBtu, they are roughly split evenly between those with HCl emissions over 0.0006 lb/MMBtu and those with emissions under 0.0006 lb/MMBtu. For those with higher emissions, further reductions in HCl are possible and could be achieved with concurrent reductions in SO_2, which would provide other air quality benefits. If EPA established an emission rate of

[65] EPA's data similarly show only 6 of 31 wet FGD-equipped units that reported both HCl and SO_2 emissions had HCl emissions greater than 0.006 lb/MMBtu. So, EPA has similar results.

0.0006 lb/MMBtu, only six units (using EPA's data) would need to reduce emissions. As shown in Figure 21, HCl emission reductions could likely be achieved with SO_2 emission reductions in the wet FGD system. They could also potentially be achieved with DSI installed upstream of the FGD system.

Figure 21. HCl v SO_2 emission rate (lb/MMBtu) for wet FGD-equipped units[66]



ATP's 2022 report determined that a wet FGD upgrade could be performed at a capital cost of roughly \$38/kW.[67] This is also in the same range as the cost of a DSI system, were that to be added in lieu of an FGD upgrade. The advantage of a wet FGD upgrade would be that there is no variable operating cost.

The impact of the capital cost on generation for a wet FGD upgrade is a significant improvement in both HCl and SO_2 removal. If there is a total of six 500 MW units, that would total roughly \$14 million annualized.

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[66] ATP 2022 Report

[67] This was 2016 dollars and in 2019 dollars is \$43/kW.

c. DSI-equipped units

ATP's 2022 report demonstrated that baghouse-equipped units that also have DSI tend to have low HCl emission rates – all well below 0.0006 lb/MMBtu. See Figure 22. Therefore, the units that are of concern for reducing HCl emissions are units with ESPs. The ESP-equipped units had SO_2 emissions as low as 0.33 lb/MMBtu with an HCl emission rate at that unit of under 0.0002 lb/MMBtu. The units with HCl emissions over 0.0006 lb/MMBtu had HCl emissions as high as 0.0011 lb/MMBtu and SO_2 emissions between 0.51 and 0.61 lb/MMBtu.

For ESP-equipped units, if an fPM limit caused the ESP-equipped unit to install a fabric filter, the unit would certainly have HCl emission levels below 0.0006 lb/MMBtu and would incur no additional costs to comply with the lower HCl limit. If that ESP-equipped unit did not install a fabric filter, increasing DSI injection rate or changes in coal type could most likely reduce HCl emissions sufficiently to achieve a standard of 0.0006 lb/MMBtu, with potential benefits in SO_2 emissions. EPA claims that it "does not have information on the sorbent injection rates for DSI systems; so, we cannot assess whether increased sorbent injection would result in additional HCl emission reductions."[68] ATP disagrees. As described in ATP's 2022 report, there have been improvements in DSI technology, and performance curves are publicly available (HCl and SO_2 capture versus treatment rate). EPA has data available to it to perform these calculations for each affected unit.[69] Alternatively, EPA could do a more generic calculation, as it did for the Hg limit for lignite units, performing a calculation for a model plant using generic (but up to date) treatment rates.

Figure 20 shows 11 DSI-equipped units that have HCl emissions greater than 0.0006 lb/MMBtu. Assuming all of them are ESP-equipped, 350 MW,[70] with average capacity factor of 50%, and on average need to increase their treatment rate at a cost of roughly $5.5/MWhr,[71] the incremental annualized cost is $93 million for all units. As noted, this cost is much lower if these units install baghouses for fPM emission control.

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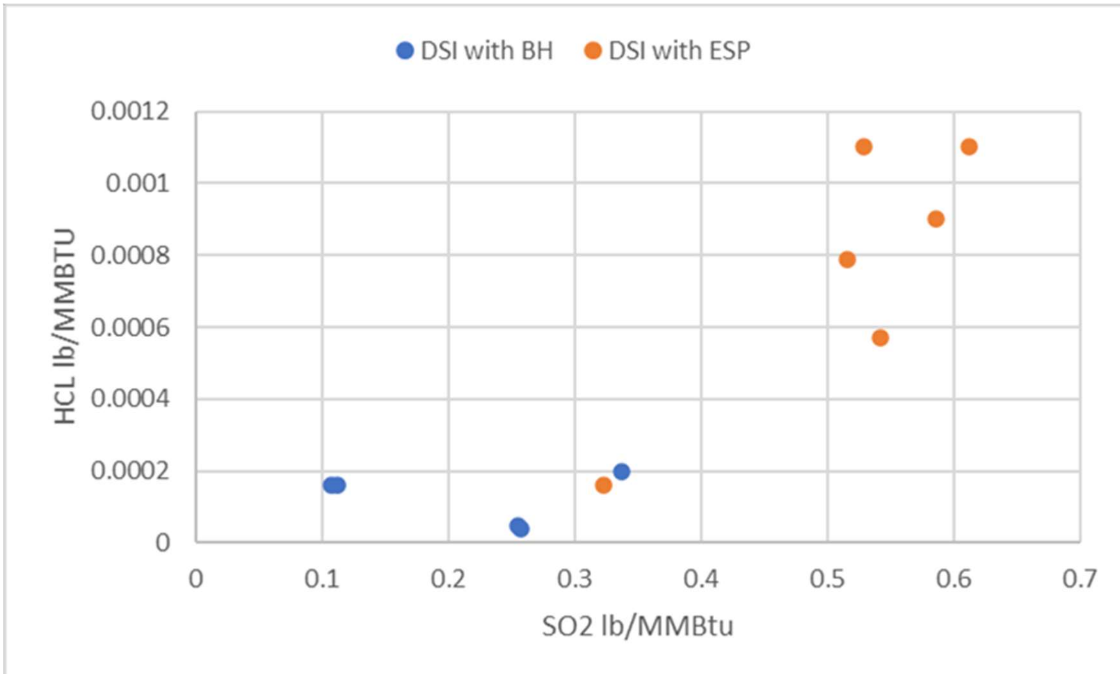
[68] 88 Fed. Reg. 24,833

[69] Uncontrolled SO_2 levels are readily calculated from EIA Form 923 fuel data and controlled SO_2 level is reported. For these units, HCl emissions are reported.

[70] The least well controlled units without retirement plans until after 2028 are generally smaller units.

[71] Sargent & Lundy, "IPM Model – Updates to Cost and Performance for APC Technologies Dry Sorbent Injection for SO2/HCl Control Cost Development Methodology – Final", April 2017, pg. 8, see VOM cost.

Figure 22. HCl and SO_2 emission rates for DSI-equipped units with baghouses or with ESPs



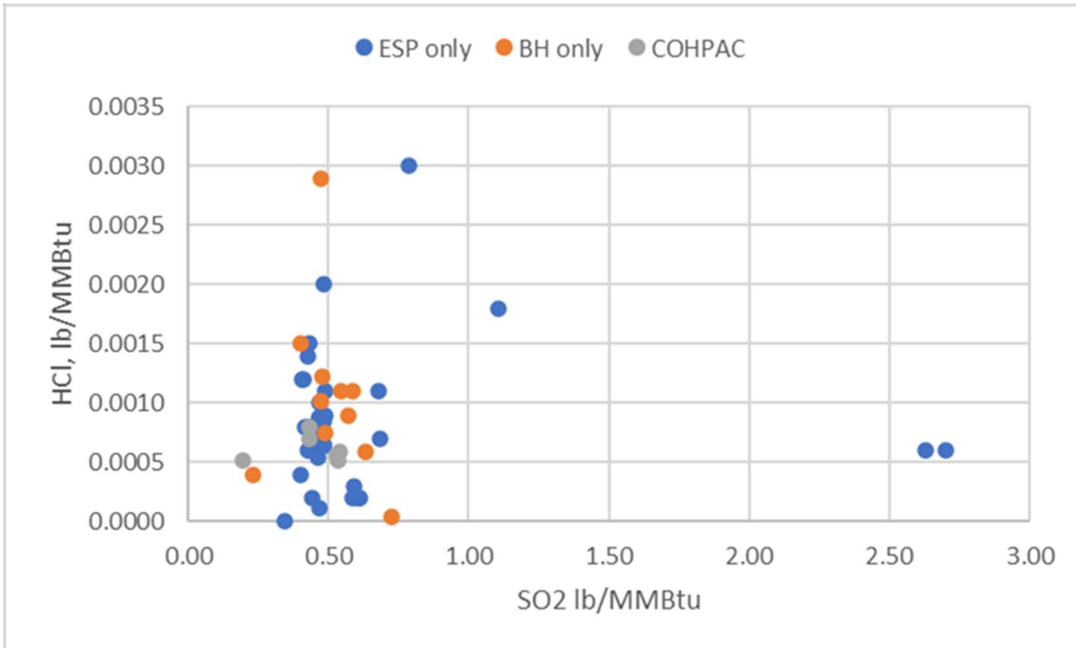
d. Uncontrolled units

Uncontrolled units can install DSI to meet an HCl emission limit of 0.0006 lb/MMBtu. This is a proven, cost-effective technology as evidenced by the number of facilities that currently deploy it. It would contribute to significant HCl reductions, as demonstrated by the fact that many of these facilities have significantly higher HCl emission rates than the highest HCl emission rates of DSI-equipped units (see Figure 23). Addition of DSI to these units would also contribute to significant reductions in SO_2 emissions.

ATP estimates that after an fPM limit of 0.006 lb/MMBtu and for an HCl emission level of 0.0006 lb/MMBtu, at most 27 units (9,013 MW) might install DSI. This would result in an annualized capital cost of about $42 million. Annual VOM would be at roughly the same level, but depends upon the levels of reduction needed, with a total cost of about $84 million.

If these units required baghouses to comply with a lower fPM limit, costs to comply with an HCl limit of 0.0006 lb/MMBtu would likely be significantly lower largely because of reduced sorbent usage, which means lower VOM and slightly lower equipment costs.

Figure 23. HCl and SO_2 emissions for units without any form of acid gas/SO_2 control and only PM controls, by PM control device[72]



E. Time to comply

Three years is a more than adequate time to comply with the proposed rule and with any of the more stringent options discussed in this report. In many cases compliance is possible in much shorter periods of time.

The proposed rule places no additional control requirements on most facilities, and for those facilities that do need to implement controls, these can all be deployed well within a three year period of time. Most can be deployed in far less than three years. Some of the technologies that might be deployed for the proposed rule or for some of the more stringent emission standards examined here are as follows:

- CEMS – CEMS, in general, can be deployed in a matter of months. All facilities could have PM CEMS and HCl CEMS installed within a year.
- Baghouses – Baghouses are the most expensive and complex technology envisioned for controlling some of the pollutants regulated in this rule. Baghouses are only envisioned to be installed for the more stringent emission levels that are examined in this report. Three years is more than adequate for installation of baghouses even under the most stringent standards examined here, and in fact two

[72] As explained in the 2021 ATP report, COHPAC is an acronym for COmpact Hybrid PArticle Collector. A COHPAC system is a PM collection system that combines an ESP followed by a downstream baghouse.

years might be sufficient depending upon the number of baghouses that would be necessary to comply with the rule. For the 2012 MATS rule, EPA anticipated 100 GW of baghouse installations. That rule permitted a three-year timeline with up to an additional year depending upon the circumstances. Even under the most stringent standards examined here, that scale of baghouse deployment is not anticipated and three years is more than adequate.

- Baghouse upgrades – Baghouse upgrades (replacement of filter media) can be performed in a matter of months.
- ESP upgrades – Depending upon the complexity of the upgrade, these can be completed in well under a year, or perhaps up to two years for the most complex upgrades.
- ACI systems – An ACI system can be installed in roughly 12-18 months, including permitting, engineering, commissioning, etc. Facilities with existing ACI systems may need to increase the treatment rate, but that is an effort that can be addressed in months, certainly under a year even if many facilities do this. No new ACI systems are envisioned in the proposed rule. For the proposed rule, increased treatment rate is expected at lignite facilities.
- Hg chemical control systems – Fuel or scrubber chemical additive systems can be deployed in a matter of months, with most time spent on testing and verification.
- DSI systems – From an equipment standpoint, these are like ACI systems, and therefore have similar project timelines.
- FGD upgrades – As described in the 2022 ATP report, these upgrades usually entail modifications to the atomization systems and installation of flow-control devices to existing systems. They can generally be deployed in about a 12-18 month period.

For the proposed rule, two baghouses are estimated by ATP to be installed.[73] ESP upgrades are forecast for about 21 facilities. The other facilities could comply with the proposed fPM standard with little or no changes. Lignite units affected by the proposed Hg standard would only need to increase carbon or chemical rates. As a result, for the vast majority of units, no more than a year would be needed to comply with the proposed rule.

To comply with more-stringent Hg, fPM, and HCl standards, most control options would require at most two years to implement. Those facilities that install baghouses to comply with more-stringent fPM or Hg standards will need potentially over two years to comply with the rule.

[73] These are estimated to be installed at Colstrip plant, which currently controls PM with wet scrubbers to about 0.020 lb/MMBtu. It may be possible for this plant to achieve lower emission limits using other means, such as a wet ESP or a modification to the wet scrubber. So, this is a conservative assumption for this plant.

III. Appendix

ATP estimated costs for fPM control (2019 dollars)

fPM limit, lb/MMBtu / BH default rate	0.015	0.010	0.006	0.004	0.0024/0.0027	0.0015/0.0027	0.0015/0.0018
Capital	$268,188,204	$944,818,378	$2,992,393,171	$5,858,778,650	$12,775,395,346	$13,602,783,994	$14,837,234,293
Annualized capital	$29,500,702	$103,930,022	$329,163,249	$644,465,652	$1,405,293,488	$1,496,306,239	$1,632,095,772
O&M	$15,602,345	$47,089,442	$112,525,929	$169,394,242	$227,659,423	$241,380,937	$241,380,937
Total annual	$44,858,778	$151,398,375	$441,858,963	$814,186,819	$1,632,859,516	$1,737,156,175	$1,873,975,448
Minor ESP upgrade	2	12	18	14	10	1	1
Medium ESP upgrade	5	3	14	16	5	10	4
Major ESP upgrade	1	6	12	18	0	8	0
New BH	0	2	11	30	91	93	107
$/MWh	$0.08	$0.28	$0.81	$1.48	$2.98	$3.17	$3.42

ATP estimated costs for Hg control of lignite (low-rank) coal units (2019 dollars)

PM rate, lb/MMBtu	0.006	0.004	0.0024	0.006	0.004	0.0024
Hg, lignite or low-rank (LR), lb/TBtu	0.5	0.5	0.5	1.2	1.2	1.2
Total capital	$376,820,576.22	$376,820,576.22	$58,450,987.63	$0.00	$0.00	$0.00
Annualized capital	$41,450,263.38	$41,450,263.38	$6,429,608.64	$0.00	$0.00	$0.00
FOM	$1,397,171.50	$1,397,171.50	$0.00	$0.00	$0.00	$0.00
VOM	$20,408,924.12	$15,083,556.96	$4,877,010.21	$5,410,280.39	$3,794,566.45	$1,507,485.09
Operating cost	$21,806,095.61	$16,480,728.46	$4,877,010.21	$5,410,280.39	$3,794,566.45	$1,507,485.09
Total annual cost	$63,256,359.00	$57,930,991.84	$11,306,618.85	$5,410,280.39	$3,794,566.45	$1,507,485.09
$/lb	$59,821.76	$54,785.54	$10,692.71	$7,058.86	$4,950.82	$1,966.83
$/MWhr	$1.33	$1.22	$0.24	$0.11	$0.08	$0.03

ATP estimated costs for Hg control of not-lignite (not-low-rank) coal units (2019 dollars)

PM rate, lb/MMBtu	0.006	0.004	0.0024	0.006	0.004	0.0024
Hg, not lignite or not-low-rank (NLR), lb/TBtu	0.15	0.15	0.15	0.5	0.5	0.5
Total capital	$2,676,474,805	$2,552,670,340	$1,301,653,961	$308,578,364	$308,578,364	$302,264,491
Annualized capital	$294,412,229	$280,793,737	$143,181,936	$33,943,620	$33,943,620	$33,249,094
FOM	$12,229,052	$11,718,773	$6,334,003	$2,610,646	$2,610,646	$2,610,646
VOM	$98,412,519	$79,691,555	$5,866,876	$11,568,804	$7,936,685	-$22,195,473
Operating cost	$110,641,572	$91,410,328	$12,200,879	$14,179,451	$10,547,331	-$19,584,827
Total annual cost	$405,053,800	$372,204,065	$155,382,815	$48,123,071	$44,490,951	$13,664,267
$/lb	$207,974	$191,108	$79,781	$57,755	$53,396	$16,399
$/MWhr	$0.81	$0.74	$0.31	$0.10	$0.09	$0.03