6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA-HQ-OAR-2002-0058; FRL-10010-81-OAR]

RIN 2060-AU20

National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters; Amendments

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: On January 31, 2013, the U.S. Environmental Protection Agency (EPA) finalized amendments to the national emission standards (NESHAP) for the control of hazardous air pollutants (HAP) at major sources from new and existing industrial, commercial, and institutional (ICI) boilers and process heaters. Subsequently, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit), in a decision issued in July 2016, remanded several of the emission standards to the EPA based on the court’s review of the EPA’s approach to setting those standards. In response to these remands, this action proposes to amend several numeric emission limits for new and existing boilers and process heaters consistent with the court’s opinion and set compliance dates for these new emission limits. The court also remanded for further explanation the Agency’s use of carbon monoxide (CO) as a surrogate for organic HAP and, in a subsequent decision in March 2018, remanded for further explanation the Agency’s use of a CO threshold to represent the application of the maximum achievable control technology (MACT) for organic HAP. The proposed changes to the emissions limits will protect

air quality and promote public health by reducing emissions of the HAP listed in the Clean Air Act (CAA). This action also addresses the two issues remanded to the EPA for further explanation. We are also proposing several technical clarifications and corrections.

DATES: *Comments*. Comments must be received on or before **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before **[INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

Public hearing. If anyone contacts us requesting a public hearing on or before **[INSERT DATE 5 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, we will hold a virtual public hearing. See **SUPPLEMENTARY INFORMATION** for information on requesting and registering for a public hearing.

ADDRESSES: You may send comments, identified by Docket ID No. EPA-HQ-OAR-2002-0058, by any of the following methods:

- Federal eRulemaking Portal: *https://www.regulations.gov/* (our preferred method). Follow the online instructions for submitting comments.

- Email: *a-and-r-docket@epa.gov*. Include Docket ID No. EPA-HQ-OAR-2002-0058 in the subject line of the message.

Instructions: All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to *https://www.regulations.gov/*, including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the **SUPPLEMENTARY INFORMATION** section of this document. Out of an abundance of caution for members of the public and our staff, the EPA Docket Center and Reading Room was closed to public visitors on March 31, 2020, to reduce the risk of transmitting COVID-19. Our Docket Center staff will continue to provide remote customer service via email, phone, and webform. We encourage the public to submit comments via *https://www.regulations.gov/* or email, as there is a temporary suspension of mail delivery to the EPA, and no hand deliveries are currently accepted. For further information on EPA Docket Center services and the current status, please visit us online at *https://www.epa.gov/dockets*.

If requested, the virtual hearing will be held on **[INSERT DATE 15 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. The hearing will convene at 9:00 a.m. Eastern Standard Time (EST) and will conclude at 3:00 p.m. EST. The EPA will announce further details on the virtual public hearing website at *https://www.epa.gov/stationary-sources-air-pollution/industrial-commercial-and-institutional-boilers-and-process-heaters*. Refer to the **SUPPLEMENTARY INFORMATION** section below for additional information.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Mr. Jim Eddinger, Sector Policies and Programs Division (D243-01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541-5426; and email address: *eddinger.jim@epa.gov*.

SUPPLEMENTARY INFORMATION:

Participation in virtual public hearing. Please note that the EPA is deviating from its typical approach because the President has declared a national emergency. Due to the current

Centers for Disease Control and Prevention (CDC) recommendations, as well as state and local orders for social distancing to limit the spread of COVID-19, the EPA cannot hold in-person public meetings at this time.

If a public hearing is requested, the EPA will begin pre-registering speakers for the hearing upon publication of this document in the Federal Register. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/stationary-sources-air-pollution/industrial-commercial-and-institutional-boilers-and-process-heaters* or contact Ms. Adrian Gates at (919) 541-4860 or by email at *gates.adrian@epa.gov* to register to speak at the virtual public hearing. The last day to pre-register to speak at the hearing will be **[INSERT DATE 13 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. On **[INSERT DATE 14 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, the EPA will post a general agenda for the hearing that will list pre-registered speakers in approximate order at *https://www.epa.gov/stationary-sources-air-pollution/industrial-commercial-and-institutional-boilers-and-process-heaters.*

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearing to run either ahead of schedule or behind schedule.

Each commenter will have 5 minutes to provide oral testimony. The EPA encourages commenters to provide the EPA with a copy of their oral testimony electronically (via email) by emailing it to Jim Eddinger and Adrian Gates. The EPA also recommends submitting the text of your oral testimony as written comments to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral testimony and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/stationary-sources-air-pollution/industrial-commercial-and-institutional-boilers-and-process-heaters*. While the EPA expects the hearing to go forward as set forth above, if requested, please monitor our website or contact Adrian Gates at 919-541-4862 or gates.adrian@epa.gov to determine if there are any updates. The EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require the services of a translator or a special accommodation such as audio description, please pre-register for the hearing with Adrian Gates and describe your needs by **[INSERT DATE 7 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. The EPA may not be able to arrange accommodations without advance notice.

Docket. The EPA has established a docket for this rulemaking under Docket ID No. EPA-HQ-OAR-2002-0058. All documents in the docket are listed in Regulations.gov. Although listed, some information is not publicly available, *e.g.*, Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy. Publicly available docket materials are available electronically in Regulations.gov.

Instructions. Direct your comments to Docket ID No. EPA-HQ-OAR-2002-0058. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *https://www.regulations.gov/*, including any personal information provided, unless the comment includes information claimed to be CBI or other information whose disclosure is restricted by statute. Do not submit electronically any information that you consider to be CBI or other information whose disclosure is restricted by statue. This type of information should be submitted by mail as discussed below.

The EPA may publish any comment received to its public docket. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.*, on the Web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets*.

The *https://www.regulations.gov/* website allows you to submit your comment anonymously, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *https://www.regulations.gov/*, your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any digital storage media you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at *https://www.epa.gov/dockets*.

The EPA is temporarily suspending its Docket Center and Reading Room for public visitors to reduce the risk of transmitting COVID-19. Written comments submitted by mail are temporarily suspended and no hand deliveries will be accepted. Our Docket Center staff will continue to provide remote customer service via email, phone, and webform. We encourage the public to submit comments via *https://www.regulations.gov/*. For further information and updates on EPA Docket Center services, please visit us online at *https://www.epa.gov/dockets*.

The EPA continues to carefully and continuously monitor information from the CDC, local area health departments, and our Federal partners so that we can respond rapidly as conditions change regarding COVID-19.

Submitting CBI. Do not submit information containing CBI to the EPA through *https://www.regulations.gov/* or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, mark the outside of the digital storage media as CBI and then identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in *Instructions* above. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2.

Send or deliver information identified as CBI only to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA-HQ-OAR-2002-0058. Note that written comments containing CBI and submitted by mail may be delayed and no hand deliveries will be accepted.

Preamble acronyms and abbreviations. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

CAA	Clean Air Act
CEDRI	Compliance and Emissions Data Reporting Interface
CBI	Confidential Business Information
CEMS	continuous emission monitoring system
CFR	Code of Federal Regulations
CO	Carbon Monoxide
EPA	Environmental Protection Agency
HAP	hazardous air pollutant(s)
HCl	hydrogen chloride
Hg	mercury
ICI	industrial, commercial, and institutional
lb/MMBtu	pounds per million British thermal units
MACT	maximum achievable control technology
MPCRF	Multipollutant Control Research Facility
NAICS	North American Industry Classification System
NESHAP	national emission standards for hazardous air pollutants
OAQPS	Office of Air Quality Planning and Standards
OMB	Office of Management and Budget
PAH	polycyclic aromatic hydrocarbons
PM	particulate matter
ppb	parts per billion
ppm	parts per million
RDL	representative detection level
tpy	tons per year

TSM	total selected metals
UPL	upper prediction limit
VOC	volatile organic compounds

Organization of this document. The information in this preamble is organized as follows:

I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

a. Need for Regulatory Action

The NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters was promulgated on March 21, 2011, and amended on January 31, 2013, and November 20, 2015. Environmental groups and industry submitted petitions seeking judicial review of the NESHAP. On December 23, 2016, the D.C. Circuit amended its July 29, 2016 decision to remand instead of vacate certain emission standards where it held that the EPA had improperly excluded certain units in establishing the emission standards and remanded the use of CO as a surrogate for organic HAP for further explanation. In March 2018, the court in a separate case remanded the EPA's decision to set a limit of 130 parts per million (ppm) CO as a minimum standard for certain subcategories for further explanation. The courts did not set specific deadlines for the EPA to issue revised regulations as part of either remand.

In response to these remands, the EPA is proposing to amend several emission standards consistent with the court's opinion and proposing responses to the two issues remanded for further explanation.

b. Legal Authority

The statutory authority for this proposed rulemaking is section 112 of the CAA. Title III of the CAA Amendments was enacted to reduce nationwide air toxic emissions. Section 112(d)(2) of the CAA directs the EPA to develop NESHAP which require existing and new major sources to control emissions of HAP using MACT based standards. This NESHAP applies to all ICI boilers and process heaters located at major sources of HAP emissions.[1]

2. Summary of the Major Provisions of the Regulatory Action In Question

The EPA is proposing to revise 34 different emission limits which it had previously promulgated in 2011 and amended in, 2013. Of these 34 emission limits, 28 of the limits would become more stringent and six of the limits would become less stringent. EPA is also proposing that facilities would have up to 3 years after the effective date of the final rule to demonstrate compliance with these revised emission limits. A list of each combination of subcategory and pollutant where the limits have proposed revisions is shown in Table 1.

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[1] See 75 FR 32016 and section 63.7575 “What definitions apply to this subpart” of 40 CFR part 63, subpart DDDDD for definitions of ICI boilers and process heaters.

TABLE 1. SUMMARY OF SUBCATEGORIES WITH PROPOSED REVISIONS TO EMISSION LIMITS

Subcategory	Pollutant where a limit is proposed to change
New-Solid	HCl
New-Dry Biomass Stoker	TSM
New-Biomass Fluidized Bed	CO, PM, TSM
New-Biomass Suspension Burner	CO, TSM
New-Biomass Hybrid Suspension Grate	CO
New-Biomass Dutch Oven/Pile Burner	PM
New-Biomass Dutch Oven/Pile Burner	PM
New-Biomass Dutch Oven/Pile Burner	CO, PM
New-Liquid	HCl
New-Heavy Liquid	PM, TSM
New-Process Gas	PM
Existing-Solid	HCl, Hg
Existing-Coal	PM
Existing-Coal Stoker	CO
Existing-Dry Biomass Stoker	TSM
Existing-Wet Biomass Stoker	CO, PM, TSM
Existing-Biomass Fluidized Bed	CO, PM, TSM
Existing-Biomass Suspension Burners	PM, TSM
Existing-Biomass Dutch Oven/Pile Burner	PM
Existing-Liquid	Hg
Existing-Heavy Liquid	PM
Existing-Non-continental Liquid	PM
Existing-Process Gas	PM

3. Costs and Benefits

We have estimated certain cost and benefits of the proposed rule, and these are found in Table 2. Present values (PV) of the net co-benefits, in 2016 dollars and discounted to 2020, are from $655 million to $1,575 million when using a 7-percent discount rate and from $751 million to $1,871 million when using a 3-percent discount rate. The equivalent annualized values (EAV) of the net co-benefits are from $78 million to $194 million per year when using a 7-percent discount rate and from $92 million to $232 million per year when using a 3-percent discount rate. All of these estimates are in 2016 dollars. The monetized benefits estimate reflects an annual average of 251 tons of fine particulate matter ($PM_{2.5}$) emission reductions per year and 393 tons of sulfur dioxide (SO_2) emission reductions per year. These benefits are referred to as ancillary co-benefits since these pollutants are not targeted for control in the proposal. The unmonetized benefits include: reduced exposure to HAP, including mercury (Hg), hydrochloric acid (HCl), non-Hg metals (*e.g.*, antimony, cadmium), formaldehyde, benzene, and polycyclic organic matter; reduced climate effects due to reduced black carbon emissions; reduced ecosystem effects; and reduced visibility impairments. We represent the present value of unmonetized benefits from affected HAP emission reductions as a C, and this is part of the net benefits estimate. We represent the equivalent annualized value of unmonetized benefits from affected HAP emission reductions as a D, and this is part of the net benefits estimate. These estimates also include climate co-disbenefits resulting from an increase in carbon dioxide (CO_2) emissions, a secondary impact from electricity use by additional control devices in response to the proposal. This disbenefit is \$0.09 million at a 3-percent discount rate and \$0.01 million at a 7-percent discount rate.

More information on these impacts can be found in section V of this preamble and in the Regulatory Impact Analysis (RIA) for this proposal.

TABLE 2. SUMMARY OF PRESENT VALUES AND EQUIVALENT ANNUALIZED VALUES FOR ANNUAL COSTS, MONETIZED ANCILLARY CO-BENEFITS, AND

MONETIZED NET BENEFITS (INCLUDING ANCILLARY CO-DISBENEFITS) FOR THE PROPOSED RULE (MILLIONS OF 2016 DOLLARS)[1,2]

		3% Discount Rate	7% Discount Rate
Present Value	Targeted Benefits[3]	C	C
	Ancillary Co-Benefits	\$730 to \$1,650	\$630 to \$1,100
	Cost[4]	\$130	\$100
	Net Benefits[5]	\$600 to \$1,520 + C	\$530 to \$1,000 + C
Equivalent Annualized Value	Targeted Benefits[6]	D	D
	Ancillary Co-Benefits	\$100 to 240	\$90 to 180
	Costs	18	17
	Net Benefits	\$80 to 220 + D	\$70 to 160 + D

[1] All estimates in this table are rounded to one decimal point, so numbers may not sum due to independent rounding.

[2] All estimates reflect the amendments to the ICI Boilers MACT standard included in this proposal from a baseline that includes the control technologies applied to meet the MACT standard.

[3] C represents the present value of unquantified benefits from reductions in targeted HAP emissions

[4] The annualized present value of costs and benefits are calculated over an 8-year period from 2021 to 2028.

[5] The total monetized ancillary co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of directly emitted $PM_{2.5}$ and SO_2. Monetized ancillary co-benefits include many, but not all, health effects associated with $PM_{2.5}$ exposure. Co-benefits are shown as a range from Krewski *et al.* (2009) to Lepeule *et al.* (2012). We do not report the total monetized ancillary co-benefits by $PM_{2.5}$ species. The ancillary climate co-disbenefits from additional CO_2 emissions resulting from control device operations are included in the results given the rounding convention employed in this table as stated in footnote a. The net benefits calculation consists of the targeted benefits and ancillary co-benefits minus the social costs.

[6] D represents the equivalent annualized value of unquantified benefits from reductions in targeted HAP emissions.

B. Does this action apply to me?

Table 3 of this preamble lists the NESHAP and associated regulated industrial source categories that are the subject of this proposal. Table 3 is not intended to be exhaustive, but rather provides a guide for readers regarding the entities that this proposed action is likely to affect. The proposed standards, once promulgated, will be directly applicable to the affected sources. As defined in the *Initial List of Categories of Sources Under Section 112(c)(1) of the*

Clean Air Act Amendments of 1990 (see 57 FR 31576, July 16, 1992) and *Documentation for Developing the Initial Source Category List, Final Report* (see EPA-450/3-91-030, July 1992), the Industrial Boiler source category includes boilers used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity. The Institutional/Commercial Boilers source category includes, but is not limited to, boilers used in commercial establishments, medical centers, research centers, institutions of higher education, hotels, and laundries to provide electricity, steam, and/or hot water. Waste heat boilers are excluded from this definition. The Process Heaters source category includes, but is not limited to, secondary metals process heaters, petroleum and chemical industry process heaters, and other process heaters. A process heater is defined as an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (*e.g.*, glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition. A boiler or process heater combusting solid waste is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the CAA.

TABLE 3. SOURCE CATEGORIES AFFECTED BY THIS PROPOSED ACTION

Source Category	NESHAP	NAICS code[1]	Examples of potentially regulated entities
Any industry using a boiler or process heater as defined in the final rule	Industrial, Commercial, and Institutional Boilers and Process Heaters	211	Extractors of crude petroleum and natural gas
		321	Manufacturers of lumber and wood products
		322	Pulp and paper mills
		325	Chemical manufacturers
		324	Petroleum refineries, and manufacturers of coal products
		316, 326, 339	Manufacturers of rubber and miscellaneous plastic products
		331	Steel works, blast furnaces
		332	Electroplating, plating, polishing, anodizing, and coloring
		336	Manufacturers of motor vehicle parts and accessories
		221	Electric, gas, and sanitary services
		622	Health services
		611	Educational services

[1] North American Industry Classification System.

C. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this action is available on the Internet. Following signature by the EPA Administrator, the EPA will post a copy of this proposed action at *https://www.epa.gov/industrial-commercial-and-institutional-boilers-and-process-heaters*. Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the proposal and key technical documents at this same website.

A redline version of the regulatory language that incorporates the proposed changes in this action is available in the docket for this action (Docket ID No. EPA-HQ-OAR-2002-0058).

II. Background

On March 21, 2011, the EPA established final emission standards for ICI boilers and process heaters at major sources, reflecting the application of MACT— the Boiler MACT (76

FR 15608). On January 31, 2013, the EPA promulgated final amendments to the Boiler MACT (78 FR 7138). On November 20, 2015, the EPA promulgated additional amendments to the Boiler MACT (80 FR 72789) in response to certain reconsideration issues, but other issues remained unresolved due to pending litigation at the time these final amendments were published.

On July 29, 2016, the D.C. Circuit issued its decision in *U.S. Sugar Corp v. EPA*, 830 F.3d 579. In that decision, the court upheld the EPA's 2013 Boiler MACT against all challenges brought by industry petitioners, and virtually all challenges brought by environmental petitioners. However, the court vacated the MACT floor emission limits for those subcategories where the EPA had excluded certain units from its MACT-floor calculation because those units burned less than 90 percent of the subcategory defining fuel. *U. S. Sugar Corp. v. EPA*, 830 F.3d at 631. On December 23, 2016, the D.C. Circuit granted EPA's motion for rehearing on remedy and remanded without vacatur these affected MACT standards. 844 F.3d 268. Therefore, these MACT standards have remained in effect since the court's decision.

Additionally, the court in *U.S. Sugar* remanded the use of CO as a surrogate for non-dioxin organic HAP to the EPA for the limited purpose of addressing the potential availability of post-combustion control technologies that could control CO. In a subsequent decision on March 16, 2018, the D.C. Circuit remanded the EPA's decision to set a limit of 130 ppm CO as a surrogate for non-dioxin organic HAP for certain subcategories, again asking the Agency to better explain its analysis supporting its decision. *Sierra Club v. EPA,* 884 F.3d 1185.

In this action, the EPA is proposing changes to certain emissions limits in the final rule and is providing additional explanation of certain issues relating to the CO standards in response to these remands. The EPA is also proposing several technical corrections.

A. What is the statutory authority for this action?

Section 112 of the CAA establishes a regulatory process to address emissions of HAP from stationary sources. CAA section 112(d) requires the Agency to promulgate technology-based NESHAP for major sources. "Major sources" are defined in CAA Section 112(a) as sources that emit or have the potential to emit 10 tons or more per year (tpy) of a single HAP or 25 tpy or more of any combination of HAP. For major sources, the technology-based NESHAP must require the maximum degree of reduction in emissions of HAP achievable (after considering cost, energy requirements, and non-air quality health and environmental impacts). These standards are commonly referred to as MACT standards.

The MACT "floor" is the minimum control level allowed for MACT standards promulgated under CAA section 112(d)(3) and may not be based on cost considerations. For new sources, the MACT floor cannot be less stringent than the emissions control that is achieved in practice by the best controlled similar source. The MACT floor for existing sources may be less stringent than floors for new sources but may not be less stringent than the average emissions limitation achieved by the best-performing 12 percent of existing sources in the category or subcategory (or the best-performing five sources for categories or subcategories with fewer than 30 sources). In developing MACT standards, the EPA must also consider control options that are more stringent than the floor (*i.e.*, "beyond-the-floor" options) under CAA section 112(d)(2). We may establish beyond-the-floor standards more stringent than the floor based on considerations of the cost of achieving the emission reductions, any non-air quality health and environmental impacts, and energy requirements.

III. Discussion of the Proposed Amendments

A. Revisions to MACT Floor Emission Limits

1. Revisions to MACT Floor Ranking Methodology for Co-Fired Units

Many of the affected sources subject to numerical limits under the NESHAP involve boilers and process heaters that co-fire multiple fuel types. In the January 2013 final rule amendments, the EPA defined each subcategory using a threshold of at least 10 percent of a subcategory-defining fuel, on an annual heat input basis. These definitions were set up in a hierarchical manner. Solid fuel units must burn at least 10-percent solid fuel. Coal and solid fossil fuel units must burn at least 10-percent coal or another solid fossil fuel. Biomass units must burn at least 10-percent biomass, but less than 10-percent coal. Liquid fuel units may burn any liquid fuel but less than 10-percent coal or fossil solid, and less than 10-percent biomass. The MACT floor analysis conducted in the 2013 rulemaking used a 90-percent fuel threshold, instead of the regulatory definition of 10 percent, to group test data into subcategories for ranking the best performers and calculating the MACT floors. This approach excluded several units that were in the subcategory from the ranking analysis, which in turn excluded these boilers from consideration in upper prediction limit (UPL) calculations to establish the MACT floor.

The D.C. Circuit in *U.S. Sugar* stated that, if EPA includes a source in a subcategory, it must consider whether any source in that subcategory is a best-performing source which would then need to be accounted for in setting the MACT floor. *U.S. Sugar v. EPA*, 830 F.3d at 631. Following the EPA's request for rehearing, the court remanded standards affected by its decision to the EPA for further consideration, and the EPA is now proposing to revise the affected standards consistent with the court's opinion.

For this proposal, the same dataset used as the basis for the 2013 final rule was used as the basis of the calculations for the proposed revised standards.[2] The EPA performed a more detailed review of the units in the dataset that had previously been excluded from the rankings, with emphasis on the newly identified best performers. While checking background test reports, the EPA corrected some database errors, filled information gaps for certain co-fired fuel blends, and adjusted CO instrument span measurements. However, since the proposed revisions are solely to address the remand in *U.S. Sugar*, we re-ran the MACT floor analysis to incorporate data that had been previously excluded. The rankings of each subcategory were revised to incorporate data from tests that fired at least 10 percent of a subcategory-defining fuel. This change in criteria impacted the number of units with emission test data for certain subcategories. In many cases test data for co-fired units in the 2013 Emissions Database did not quantify the exact fuel input breakdown.[3] The EPA reviewed test reports that were included as background data materials for the 2013 Emissions Database and conducted outreach with selected facilities in order to verify to which subcategory the various test data belonged. Appendix B of the docketed memorandum, *Revised MACT Floor Analysis (2019) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source* (2019 MACT Floor Memo), details the revised ranking of each subcategory and compares the ranking to the previous ranking assignment from the January 2013 final rule. As was done in the January 2013 final rule, devices that were co-firing solid waste

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[2] Emissions Database for Boilers and Process Heaters Containing Stack Test, CEM, and Fuel Analysis Data Reporting under ICR No. 2286.01 and ICR No.2286.03 (OMB Control Number 2060-0616) (version 8). Docket ID No. EPA-HQ-OAR-2002-0058-3830.

[3] Ibid.

materials were excluded from the ranking unless the device was exempted from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the CAA.

As part of the revisions to the ranking analysis, the EPA also made corrections to some of the emissions data, as part of its data quality review of the revised set of best performing units in each subcategory. The EPA investigated historical notes in the 2013 Emissions Database about whether certain test results were valid or were previously excluded due to data quality concerns. When historical notes had excluded data, those exclusions were carried forward into the revised analysis supporting the proposal. Because some new best performing units were identified in the ranking analysis, the EPA also reviewed test reports that were available in the rulemaking docket to verify reported emission results in the database as well as oxygen adjustment factors, and CO instrument span and CO calibration data. EPA made corrections to the values used in the MACT floor analysis when these back-up documents suggested a correction was needed. In addition to data available from the docketed data resources, the EPA also received data correction files and a small number of additional tests from members of the American Forest and Paper Association. The EPA reviewed the additional data provided, including any supporting emission test reports to evaluate if the data were accurate and complete and representative prior to including the data in the revised ranking analysis. A summary of data changes made since version 8 of the database is available in the docketed memorandum, *Summary of 2019 Emission Database Changes for Major Source Boilers and Process Heaters*. In addition, a summary of the expected impacts of these data changes is available in the *Regulatory Impact Analysis for the Proposed ICI Boilers NESHAP Reconsideration*, which is available in the docket for this action. The changes include an increase in compliance costs as well as an increase in emission reductions as a result of the more stringent emission limits.

a. Existing Sources

Because the rankings shifted dramatically, the number of units in each of the subcategories changed, as well as the specific units that comprised the top 12 percent within the subcategory. Appendix B-1 of the 2019 MACT Floor Memo summarizes the revised number of units in the top 12 percent for each combination of subcategory and pollutant. The remainder of the worksheets in Appendix B indicate which units are identified to be among the top 12 percent.

Once the top 12 percent of units were identified, each unique combination of pollutant and subcategory data was reviewed to determine the distribution of the dataset and then calculate the UPL. The procedures for determining the data distribution and calculating the UPL remain the same as they did for the January 2013 final rule, with the exception of "limited datasets" which are those that consisted of less than seven test runs. The procedures for determining the distribution and calculating the UPL are detailed in *EPA's Response to Remand of the Record for Major Source Boilers, July 14, 2014* available in the docket for this action. Additional considerations for limited datasets are discussed in section III.A.2 of this preamble. The actual calculations and distribution assignments for each pollutant and subcategory combination are shown in Appendix C of the 2019 MACT Floor Memo. The EPA is not soliciting comment on its use of the same methodology that it used to set the January 2013 standards, but is soliciting comment on the proposed revisions to the standards the Agency is proposing to address concerning the court's remand in *U.S. Sugar*.

Once the UPL values were calculated, the EPA reviewed whether any additional fuel variability factors were available to multiply by the calculated UPL for Hg, HCl, and total selected metals[4] (TSM). The methodology for computing the fuel variability factor did not change since the January 2013 final rule. Instead, any changes in the fuel variability factors occurred because of changes to the units that constituted the top 12 percent for each subcategory and were, therefore, eligible for consideration in the fuel variability factor analysis. The fuel variability factor calculations are shown in Appendix A of the 2019 MACT Floor Memo. Fuel variability factors were available for solid and liquid fuel subcategories for Hg and HCl and for biomass fluidized bed, coal, and heavy liquid subcategories for TSM.

b. New Sources

Similar to existing sources, the re-ranking of the data for each new source subcategory impacted the specific units that were identified as the lowest emitting for each combination of pollutant and subcategory.

Additionally, as in the January 2013 final rule, the EPA did not allow units with a nitrogen oxides-to-CO ratio above 50 to represent a best performing boiler for CO. Instead, the EPA picked the next lowest ranked unit for the Coal Stokers. Additionally, as in the January 2013 final rule, the EPA only considered units with at least three test runs to serve as the basis of the new source floor except for cases where no other data were available. This occurred only for the TSM UPL calculations for new Biomass Suspension Burner. In that case, the second ranked unit was selected. The revisions to the emissions standards proposed here are for the limited purpose of addressing the court's remand in *U.S. Sugar*, and the EPA is not proposing or soliciting comment on other aspects of the standards or methodology used to calculate the standards.

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[4] Total selected metals is the sum of the non-Hg HAP metals - arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium.

Once the best controlled similar source for each subcategory was identified, each unique combination of pollutant and subcategory data was reviewed to determine the distribution of the dataset and then calculate the UPL. The procedures for determining the data distribution and calculating the UPL remain the same as for the January 2013 final rule, with the exception of limited datasets that consisted of less than seven test runs or in cases where the calculated new source UPL exceeded the existing source UPL for the same subcategory. The procedures for determining the distribution and calculating the UPL are detailed in the docketed memorandum, *Revised MACT Floor Analysis (2019) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source*. Many of the new source UPL calculations involved limited datasets and additional considerations for limited datasets are discussed in section III.A.2 of this preamble. The actual calculations and distribution assignments for each pollutant and subcategory combination are shown in Appendix E of the 2019 MACT Floor Memo. This appendix worksheet for each UPL calculation also shows the ranking of each unit.

Once the UPL values were calculated, the EPA reviewed whether any additional fuel variability factors were available to multiply by the calculated UPL for Hg, HCl, and TSM. The methodology for computing the fuel variability factor did not change since the January 2013 final rule. Instead, any changes in the fuel variability factors occurred because of changes to the unit selected to represent the best controlled similar source and were, therefore, eligible for consideration in the fuel variability factor analysis for new sources. The fuel variability factor calculations are shown in Appendix A of the 2019 MACT Floor Memo. Fuel variability factors were available for liquid fuel and coal subcategories for Hg and HCl, and the heavy liquid subcategory for TSM.

The EPA also incorporated the same procedures as the January 2013 final rule to ensure that the available measurement methods would provide accurate emissions measurements at the levels set for the various standards. The procedures are discussed in detail at 76 FR 80611 and the calculated values are presented in technical memoranda in the docket.[5] The procedures remained the same, but which unit represents the new source floor did change since January 2013; so, the actual representative detection level (RDL) calculation accordingly changed as well. The revised calculations for 3 times the RDL are presented in the documented memorandum. After computing the RDL, the UPL calculations were compared to a value equal to 3 times the RDL. In the case of new sources, if the UPL was below the 3 times RDL value then the MACT floor was set equal to 3 times the RDL.

Lastly, the EPA compared the calculated UPL, or 3 times RDL values where appropriate, to the existing source emission limits for the same pollutant and subcategory. If the new source floor was larger than the existing source floor, the EPA reviewed the data further as discussed in the UPL methodology for limited datasets in section III.A.2 of this preamble to evaluate if the unit truly reflected the best controlled similar source as determined by the Administrator and to evaluate if the UPL calculations required any adjustments to ensure that the UPL did not result in a less stringent standard for new sources. In addition to the tests conducted on limited datasets, two subcategories for new source limits required additional evaluation, as discussed below. Specific names of the facility and boiler names refer to how the boilers are identified in the MACT floor analysis to allow the reader to find these units in the related technical support memoranda.

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[5] See Docket ID Item Nos.: EPA-HQ-OAR-2002-0058-3837 and EPA-HQ-OAR-2002-0058-3839.

The MACT floor dataset for particulate matter (PM) from new fluidized bed boilers designed to burn biomass includes 18 test runs from a single boiler "ORGeorgiaPacificWaunaMill, EU35 - Fluidized Bed Boiler" (EU35) that we identified as the best performing unit based on average emissions. The calculated UPL for new sources exceeded the UPL calculated for existing units in the same subcategory. After determining the correct distribution and ensuring that we used the correct equation for the distribution, we evaluated the variance of this unit. Our analysis showed that this unit, identified as the best performing unit based on average emissions, has a variance that is 3 orders of magnitude higher than the second ranked unit "WIGPGreenBay2818, B10 - Wastepaper Sludge-Fired Boiler 10" (B10) and an overall average (considering all stack tests, not just the minimum stack test average) that is approximately 4 times higher than the second ranked unit. This information indicates that the second ranked unit, B10, has a more consistent level of performance than the top ranked unit, EU35, and the resulting UPL calculations support this. The calculated UPL is lower for the second ranked unit, B10, than for the top ranked unit, EU35. For these reasons, we determined that the unit with the lowest average, EU35, is not the best performing source for this subcategory and pollutant and we are instead identifying B10 as the best performing source.

The MACT floor dataset for PM from new stoker boilers designed to burn wet biomass includes nine test runs from a single boiler "IAMonsantoMuscatine, Boiler #8 EP-195" that we identified as the best performing unit based on average emissions. The calculated UPL for new sources exceeded the UPL calculated for existing units in the same subcategory. The UPL based on a lognormal equation was 10.2 times higher than the mean. After reviewing the distribution of the dataset, we found that the distribution was incorrectly flagged as lognormally distributed instead of normally distributed. The UPL based on the normal distribution no longer exceeds the

UPL calculation for existing sources. The UPL based on a normal equation was 2.36 times higher than the mean. After correcting the distribution, we also evaluated the variance of this unit, which was 4 times lower than the variance of the next lowest ranked unit. For these reasons, we determined that the UPL based on the normal distribution was the appropriate basis for the new source floor for this subcategory.

2. UPL Methodology for Limited Datasets

In August 2013, the D.C. Circuit issued its decision in *National Ass'n. of Clean Water Agencies (NACWA) v. EPA*, which addressed challenges to the EPA's 2011 Sewage Sludge Incinerator (SSI) rule, issued under section 129 of the CAA. In *NACWA v. EPA*, the court remanded the EPA's use of the UPL methodology to the Agency for further explanation of how the methodology reflected the average emissions limitation achieved by the best-performing 12 percent of sources (for existing sources) and the average emissions limitation achieved by the best-performing similar source (for new sources). *NACWA v. EPA*, 734 F.3d 1115, 1151. Because the UPL methodology used in the SSI rule was the same as that used in the major source Boiler MACT, the EPA requested a remand of the record in *U.S. Sugar v. EPA* in order to address the court's decision in *NACWA v. EPA*. The EPA prepared a memorandum explaining the methodology for the UPL. This memorandum, *EPA's Response to Remand of the Record for Major Source Boilers,* provides a detailed rationale to use the UPL as the basis of setting a MACT floor for new and existing sources, and the methodology and the explanation in the memorandum were upheld by the D.C. Circuit in *U.S. Sugar v. EPA*. 830 F.3d at 639. Following the UPL memorandum, the EPA issued a subsequent memorandum specifically addressing the application of the UPL methodology when setting MACT emission limits with limited datasets, *Approach for Applying the Upper Prediction Limit to Limited Datasets*. In that memorandum, the EPA concluded that there are additional considerations when setting MACT floors for limited datasets. The EPA is not, in this action, proposing any revisions to or soliciting comment on either the *EPA's Response to Remand of the Record for Major Source Boilers* memorandum or the limited datasets memorandum. Rather, the EPA is proposing limited revisions to certain Boiler MACT standards to address the specific issue remanded to the Agency by the court in *U.S. Sugar v. EPA*. The docketed memorandum, *Approach for Applying the Upper Prediction Limit to Limited Datasets for Boilers and Process Heaters at Major Sources*, discusses the generic methods in the previously issued limited dataset memorandum, as well as a summary of the findings for certain boiler and process heater subcategories. A summary of those findings is also discussed here.

For the ICI Boilers and Process Heaters source categories, we have limited datasets for the following subcategories and pollutants for both existing and new sources: process gas (Hg, HCl, TSM, and PM), biomass suspension burner (TSM), dry biomass stoker (TSM, PM, and CO), and coal fluidized bed coal refuse (CO). For the ICI Boilers and Process Heaters source categories, we have limited datasets for the following subcategories and pollutants for new sources: solid (Hg and HCl), liquid (Hg and HCl), heavy liquid (TSM and PM), light liquid (TSM and PM), biomass dutch oven/pile burner (TSM), biomass fuel cell (TSM), biomass fluidized bed (TSM), biomass suspension burner (TSM), biomass suspension grate (CO), wet biomass stoker (TSM), and coal (TSM and PM). Therefore, we evaluated these specific datasets to determine whether it is appropriate to make any modifications to the UPL approach used to calculate the MACT floors. For each dataset, we performed the following steps: selected the data distribution that best represents the dataset; ensured that the correct equation for the distribution was then applied to the data; and compared individual components of the limited dataset to determine if the standards based on the limited dataset reasonably represent the performance of the units included in the dataset. The results of the limited dataset analyses are presented below for each subcategory and pollutant.

The MACT floor datasets for Hg, HCl, and PM from existing and new boilers designed to burn process gas include three test runs from a single boiler. In addition, there are no other process gas units in the rankings to select from for these pollutants. Using the available data, we first determined the correct distribution and ensured that we used the correct equation for each distribution. The MACT floor dataset for TSM from existing and new boilers designed to burn process gas only includes two test runs. We assumed a distribution of lognormal for this dataset. We then calculated the UPL-based limits which range from 1.2 to 3 times the average (mean) of all test runs from the best performing source. This result indicates that the emission limits are not unreasonable compared to the actual performance of the unit upon which the limits are based and are within the ranges that we see when we evaluate larger datasets using our MACT floor calculation procedures. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to the standard floor calculation procedure were warranted for this pollutant and subcategory.

The MACT floor dataset for TSM from existing and new suspension burner boilers designed to burn biomass includes three test runs from a single boiler that we identified as the best performing unit based on average emissions. In addition, there are no other biomass suspension burner units in the rankings to select from for this pollutant because the other unit with test data only has two test runs, and units with less than three test runs were not considered for UPL calculations if other data are available (see discussion in section III.A.1 of this preamble). Using the available data, we first determined the correct distribution and ensured that we used the correct equation for each distribution. We then calculated the UPL-based limit which is 1.7 times the short-term average emissions from the best performing source. This result indicates that the emission limit is not unreasonable compared to the actual performance of the unit upon which the limit is based and is within the range that we see when we evaluate larger datasets using our MACT floor calculation procedures. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to the standard floor calculation procedure were warranted for this pollutant and subcategory.

The MACT floor dataset for TSM from existing and new stoker boilers designed to burn dry biomass includes three test runs from a single boiler. In addition, there are no other dry biomass stoker units in the rankings to select from for this pollutant. Using the available data, we first determined the correct distribution and ensured that we used the correct equation for each distribution. We then calculated the UPL-based-limit, which is approximately 2 times the short-term average emissions from the best performing source, indicating that the emission limit is not unreasonable compared to the actual performance of the unit upon which the limit is based and is within the range that we see when we evaluate larger datasets using our MACT floor calculation procedures. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to the standard floor calculation procedure were warranted for this pollutant and subcategory.

The MACT floor datasets for PM and CO from existing and new stoker boilers designed to burn dry biomass include three test runs from a single boiler that we identified as the best performing unit based on average emissions. After determining the correct distribution and ensuring that we used the correct equation for each distribution, we evaluated the variance of this unit for each pollutant, comparing it to other boilers in the same subcategory. Our analysis showed that this unit, identified as the best performing unit based on average emissions, also had the lowest variance for each pollutant, indicating that not only did it have the lowest average emissions but also the most consistent performance. Therefore, we determined that the emission limits reasonably account for variability and that no changes to our standard floor calculation procedure were warranted for this subcategory and pollutants.

The MACT floor dataset for CO from existing and new fluidized bed boilers designed to burn coal refuse includes three test runs from a single boiler. In addition, there are no other units in the rankings to select from for this pollutant. Using the available data, we first determined the correct distribution and ensured that we used the correct equation for the distribution. We then calculated the UPL-based limit which is approximately 1.5 times the short-term average emissions from the best performing source, indicating that the emission limit is not unreasonable compared to the actual performance of the unit upon which the limit is based and is within the range that we see when we evaluate larger datasets using our MACT floor calculation procedures. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to the standard floor calculation procedure were warranted for this pollutant and subcategory.

The MACT floor dataset for Hg from new boilers designed to burn solid fuel includes six test runs from a single boiler that we identified as the best performing unit based on average emissions. After determining the correct distribution and ensuring that we used the correct equation for each distribution, we evaluated the variance of this unit, comparing it to other boilers in the same subcategory. Our analysis showed that this unit, identified as the best performing unit based on average emissions, also had the lowest variance, indicating that not only did it have the lowest average emissions but also the most consistent performance.

Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to our standard floor calculation procedure were warranted for this subcategory and pollutant.

The MACT floor dataset for HCl from new boilers designed to burn solid fuel includes six test runs from a single boiler "ARPotlatchForestWarren, Wellons Boiler" (Wellons Boiler) that we identified as the best performing unit based on average emissions. After determining the correct distribution and ensuring that we used the correct equation for each distribution, we compared the calculated UPL to the short-term average emissions and found that the unit had a UPL that was 81 times higher than the lowest short-term average emission test and that this ratio is not within the range that we see when we evaluate larger datasets using our MACT floor calculation procedures. Based on this, we evaluated the variance of this unit and concluded that further consideration of the best performer selection was warranted. The variance of the top ranked unit was 6 orders of magnitude higher than the variance of the next ranked unit "TXDibollTemple-Inland, PB-44" (PB-44). In addition, the Wellons Boiler six test runs were from two separate stack tests, and while the unit was the top ranked unit due to one of the stack test averages being very low, the other stack test average was 6.2 times higher. The high degree of variance in the dataset for the unit with the lowest average, Wellons Boiler, prompted us to question whether this unit was, in fact, the best performing unit and to evaluate the dataset for PB-44. The dataset for PB-44 includes three test runs and the average emissions are only about 7 percent higher than the Wellons Boiler lowest stack test average. However, the PB-44 average emissions are actually 97 percent lower when comparing to the Wellons Boiler average for both stack tests. This information indicates that the second ranked unit, PB-44, has a more consistent level of performance than the top ranked unit, Wellons Boiler, and the resulting UPL calculations support this. The HCl UPL value is lower for PB-44 than for Wellons Boiler and the Wellons Boiler UPL exceeded the UPL for existing solid fuel boilers. For these reasons, we determined that the unit with the lowest average, Wellons Boiler, is not the best performing source for this pollutant and we are instead determining PB-44 to be the best performing source.

The MACT floor dataset for Hg from new boilers designed to burn liquid fuel includes three test runs from a single boiler that we identified as the best performing unit based on average emissions. After determining the correct distribution and ensuring that we used the correct equation for each distribution, we evaluated the variance of this unit. Our analysis showed that this unit, identified as the best performing unit based on average emissions, and the second ranked unit both have similar and extremely low variance, indicating consistent performance. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to the standard floor calculation procedure were warranted for this subcategory and pollutant.

The MACT floor dataset for HCl from new boilers designed to burn liquid fuel includes three test runs from a single boiler that we identified as the best performing unit based on average emissions. After determining the correct distribution and ensuring that we used the correct equation for each distribution, we evaluated the variance of this unit, comparing it to other boilers in the same subcategory. Our analysis showed that this unit, identified as the best performing unit based on average emissions, also had the lowest variance, indicating that not only did it have the lowest average emissions but also the most consistent performance. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to the standard floor calculation procedure were warranted for this subcategory and pollutant.

The MACT floor dataset for TSM from new boilers designed to burn heavy liquid fuel includes three test runs from a single boiler that we identified as the best performing unit based on average emissions. After determining the correct distribution and ensuring that we used the correct equation for the distribution, we evaluated the variance of this unit, comparing it to other boilers in the same subcategory. Our analysis showed that this unit, identified as the best unit based on average emissions, had a slightly higher variance than the next ranked unit. Therefore, we also evaluated the second ranked unit and determined its distribution and applied the equation for its distribution. Comparing the calculated UPL values for the top two units, the best performing unit resulted in the lower UPL. While its variance was slightly higher, the top ranked unit's lower overall emissions and resulting UPL calculations indicate it is the best performer. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to the standard floor calculation procedure were warranted for this pollutant and subcategory.

The MACT floor dataset for PM from new boilers designed to burn heavy liquid fuel includes three test runs from a single boiler that we identified as the best performing unit based on average emissions. After determining the correct distribution and ensuring that we used the correct equation for the distribution, we evaluated the variance of this unit, comparing it to other boilers in the same subcategory. Our analysis showed that this unit, identified as the best performing unit based on average emissions, also had the lowest variance, indicating that not only did it have the lowest average emissions but also the most consistent performance. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to the standard floor calculation procedure were warranted for this pollutant and subcategory.

The MACT floor dataset for TSM from new boilers designed to burn light liquid fuel includes three test runs from a single boiler that we identified as the best performing unit based on average emissions. After determining the correct distribution and ensuring that we used the correct equation for the distribution, we evaluated the variance of this unit, comparing it to other boilers in the same subcategory. Our analysis showed that this unit, identified as the best performing unit based on average emissions, and the second ranked unit have nearly equivalent variance, indicating consistent performance. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to the standard floor calculation procedure were warranted for this pollutant and subcategory.

The MACT floor dataset for PM from new boilers designed to burn light liquid fuel includes three test runs from a single boiler that we identified as the best performing unit based on average emissions. After determining the correct distribution and ensuring that we used the correct equation for the distribution, we evaluated the variance of this unit, comparing it to other boilers in the same subcategory. Our analysis showed that this unit, identified as the best performing unit based on average emissions, also had the lowest variance, indicating that not only did it have the lowest average emissions but also the most consistent performance. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to the standard floor calculation procedure were warranted for this pollutant and subcategory.

The MACT floor dataset for TSM from new dutch oven boilers designed to burn biomass includes three test runs from a single boiler that we identified as the best performing unit based on average emissions. After determining the correct distribution and ensuring that we used the correct equation for the distribution, we evaluated the variance of this unit, comparing it to other boilers in the same subcategory. Our analysis showed that this unit, identified as the best performing unit based on average emissions, also had the lowest variance, indicating that not only did it have the lowest average emissions but also the most consistent performance. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to the standard floor calculation procedure were warranted for this pollutant and subcategory.

The MACT floor dataset for TSM from new biomass fuel cell boilers includes six test runs from a single boiler that we identified as the best performing unit based on average emissions. After determining the correct distribution and ensuring that we used the correct equation for the distribution, we evaluated the variance of this unit, comparing it to other boilers in the same subcategory. Our analysis showed that this unit, identified as the best performing unit based on average emissions, also had the lowest variance, indicating that not only did it have the lowest average emissions but also the most consistent performance. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to the standard floor calculation procedure were warranted for this pollutant and subcategory.

The MACT floor dataset for TSM from new fluidized bed boilers designed to burn biomass includes three test runs from a single boiler that we identified as the best performing unit based on average emissions. After determining the correct distribution and ensuring that we used the correct equation for the distribution, we evaluated the variance of this unit, comparing it to other boilers in the same subcategory. Our analysis showed that this unit, identified as the best performing unit based on average emissions, also had the lowest variance, indicating that not only did it have the lowest average emissions but also the most consistent performance. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to the standard floor calculation procedure were warranted for this pollutant and subcategory.

The MACT floor dataset for TSM from new suspension burners designed to burn biomass includes three test runs from a single boiler. In addition, there are no other biomass suspension burner units in the rankings to select from for this pollutant. Using the available data, we first determined the correct distribution and ensured that we used the correct equation for each distribution. We then calculated the UPL-based limit which is 1.7 times the short-term average emissions from the best performing source, indicating that the emission limit is not unreasonable compared to the actual performance of the unit upon which the limit is based and is within the range that we see when we evaluate larger datasets using our MACT floor calculation procedures. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to our standard floor calculation procedure were warranted for this subcategory and pollutant.

The MACT floor dataset for TSM from new stoker boilers designed to burn wet biomass includes six test runs from a single boiler "GAGPCelluloseBrunswick, U700 -- No. 4 Power Boiler" (U700 -- No. 4 Power Boiler) that we identified as the best performing unit based on average emissions. After determining the correct distribution and ensuring that we used the correct equation for the distribution, we evaluated the variance of this unit, comparing it to other boilers in the same subcategory. We note that the second and third ranked units each have less than three test runs, and units with less than three test runs were not considered for UPL calculations if other data are available (see discussion in section III.A.1 of this preamble). Our analysis showed that this unit, identified as the best performing unit based only on average emissions, has a higher variance than the fourth ranked unit "MESDWarrenSomerset, No. 2

Power Boiler" (No. 2 Power Boiler) and an overall average (considering all stack tests, not just the minimum stack test average) that is approximately 18 percent higher than the fourth ranked unit. This information indicates that the fourth ranked unit, No. 2 Power Boiler, has a more consistent level of performance than the top ranked unit, U700 -- No. 4 Power Boiler, and the resulting UPL calculations support this. The calculated UPL is lower for the fourth ranked unit, No. 2 Power Boiler, than for the top ranked unit, U700 -- No. 4 Power Boiler. For these reasons, we determined that the unit with the lowest average, U700 -- No. 4 Power Boiler, is not the best performing source for this subcategory and pollutant and we are instead determining that No. 2 Power Boiler is the best performing source.

The MACT floor dataset for CO from new suspension grate boilers designed to burn biomass includes three test runs from a single boiler that we identified as the best performing unit based on average emissions. After determining the correct distribution and ensuring that we used the correct equation for each distribution, we evaluated the variance of this unit, comparing it to other boilers in the same subcategory. Our analysis showed that this unit, identified as the best unit based on average emissions, also had the lowest variance, indicating that not only did it have the lowest average emissions but also the most consistent performance. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to the standard floor calculation procedure were warranted for this subcategory and pollutant.

The MACT floor dataset for TSM from new coal boilers includes six test runs from a single boiler that we identified as the best performing unit based on average emissions. After determining the correct distribution and ensuring that we used the correct equation for each distribution, we evaluated the variance of this unit and concluded that further consideration of the best performer selection was warranted. The variance of the top ranked unit was approximately 3 times higher than the variance of the next ranked unit. The degree of variance in the dataset for the unit with the lowest average prompted us to question whether this unit was, in fact, the best performing unit and to evaluate the second ranked unit. The second ranked unit includes 3 test runs. We calculated the UPL using data for the second ranked unit, however, and the resulting UPL was higher than when using data from the top ranked unit. While its variance was higher, the top ranked unit's lower overall emissions and resulting UPL calculations indicate it is the best performer. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to the standard floor calculation procedure were warranted for this subcategory and pollutant.

The MACT floor dataset for PM from new coal boilers includes six test runs from a single boiler that we identified as the best performing unit based on average emissions. After determining the correct distribution and ensuring that we used the correct equation for each distribution, we evaluated the variance of this unit and concluded that further consideration of the best performer selection was warranted. The variance of the top ranked unit was approximately 2.5 times higher than the variance of the next ranked unit. The degree of variance in the dataset for the unit with the lowest average prompted us to question whether this unit was, in fact, the best performing unit and to evaluate the second ranked unit. The second ranked unit includes three test runs. We calculated the UPL using data for the second ranked unit, however, and the resulting UPL was higher than when using data from the top ranked unit. Therefore, while its variance was higher, the top ranked unit's lower overall emissions and resulting UPL calculations indicate it is the best performer. Therefore, we determined that the emission limit reasonably accounts for variability and that no changes to the standard floor calculation procedure were warranted for this subcategory and pollutant.

The Process Gas and Coal Fluidized Bed subcategories for existing and new sources and the Heavy Liquid Fuel, Light Liquid Fuel, Pulverized Coal Boilers, and Coal Stoker subcategories for new sources have limited datasets for CO. However, the best performers have very low CO emissions and the emission limits were set equal to a minimum CO level; the applicable methodology is discussed in section III.E of this preamble.

B. Beyond-the-floor Emission Limits

We reviewed the recalculated MACT floor emission limits that are less stringent than those in the January 2013 final rule in order to assess whether a beyond-the-floor option was technically achievable and cost-effective. To assess whether the January 2013 limits were technically achievable we reviewed the compliance data available to the EPA through the Compliance and Emissions Data Reporting Interface (CEDRI) and WebFIRE[6] and compared these data to the emission limits in the January 2013 final rule to assess whether those more stringent limits were being achieved in practice. Data is submitted to CEDRI by regulated entities to EPA in order to meet electronic reporting requirements of 40 CFR Part 60 Subpart DDDDD. These reports include performance tests, CEMS relative accuracy test audits, notifications of compliance status reports, among other items. WebFIRE displays these reports to the public and can be searched by regulatory subpart or boiler process type (e.g. fuel type, boiler size). For existing sources, with the exception of TSM at coal units, all of the compliance data available for the subcategory showed that the units were complying with the more stringent 2013 emission limit. For TSM at coal-fired units, 83 percent of the units (10 of 12) with data were

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[6] U.S. Environmental Protection Agency. Compliance and Emissions Data Reporting Interface (CEDRI) *https://www.epa.gov/electronic-reporting-air-emissions/cedri* and WebFIRE database *https://www.epa.gov/electronic-reporting-air-emissions/webfire*.

below the more stringent 2013 emission limit. The two units that were not were 12 percent above the 2013 emission limit, but these units were using the emission averaging provision to comply at a common stack. To assess whether the limits were cost-effective, the EPA reviewed the control devices currently installed to determine if any cost savings would occur should the less stringent limit be selected. In all of these cases, the controls that were already installed were the same types of controls that would be required to meet either the January 2013 limits or the less stringent recalculated limits and, therefore, no additional costs would be incurred to meet the more stringent limits. There were three additional cases where the January 2013 remanded emission limit was more stringent than the recalculated emission limit, but no recent compliance data were available in these three cases. Since no data were available for PM at Gas 2 units, and TSM at biomass suspension burners or dry biomass stokers, the EPA did not select a beyond-the-floor limit for these three emission limits. In all three of these cases, where we did not have data, the changes are resulting from the revised methodology for limited datasets. The process gas unit is uncontrolled, and the dry biomass stoker and biomass suspension burner both had a multiclone installed.

Based on the review of compliance data, the EPA selected a beyond-the-floor level for 10 of the existing source emission limits, as listed in Table 4.

TABLE 4. EXISTING SOURCE EMISSION LIMITS BASED ON BEYOND-THE-FLOOR

Existing Source Subcategory Limit	Discussion
HCl-Liquid	All of the existing units with data available are below the 2013 emission limit.
TSM-Coal	All 10 of the existing units complying with the TSM limit were below the 2013 emission limit.
TSM-Heavy Liquid	The two existing units with data were both below the 2013 emission limit.
TSM-Light Liquid	The two existing units with data were both below the 2013 emission limit.

PM-Dry Biomass Stoker	All six of the existing units with data were below the 2013 limit.
CO-Biomass Suspension Burner	All 12 of the existing units with data were below the 2013 limit.
CO-Biomass Suspension Grate	All 99 of the existing units with data were below the 2013 limit.
CO-Dry Biomass Stoker	All six of the existing units with data were below the 2013 limit.
CO-Coal Fluidized Bed with Heat Exchanger	The one existing unit with data was below the 2013 limit.

For new sources, the EPA made a similar comparison to compliance data from new and existing boilers in order to assess whether the limits were achievable. In addition, for PM emission limits at new sources, consistent with the analysis taken during the January 2013 final rule, PM emission limits were compared to the PM limit of 0.03 pound per million British thermal units (lb/MMBtu) for new biomass boilers in 40 CFR part 60, subparts Db and Dc. Only biomass compliance data were available for new sources, and so the EPA compared both existing and new source compliance data, when available, to the emission limits in the January 2013 final rule. For three of the limits, all of the units with available compliance data were below the more stringent January 2013 emission limit. For the PM limit at dry biomass stokers, and the TSM limit at wet biomass stokers, all of the available new source compliance data were meeting the more stringent January 2013 emission limit. Two of the limits had no new source data available for comparison, but the TSM at coal units had 50 percent of the existing units with data below the January 2013 new source limit, and 9 percent of the coal units were below the new source limit for PM. Both of these cases demonstrate that the limits are technically achievable. There were three cases where the January 2013 remanded new source emission limit was more stringent than the emission limit calculated based on the revised MACT floor calculation methodology, but no recent compliance data were available in these four cases. These were the same three groups mentioned for existing sources, PM at Gas 2 units, and TSM at biomass suspension burners or dry biomass stokers. Due to lack of data, the EPA did not select a beyond-the-floor limit for these three emission limits. For new sources, there were seven emission limits where a beyond-the-floor level was selected, as listed in Table 5.

TABLE 5. NEW SOURCE EMISSION LIMITS BASED ON BEYOND-THE-FLOOR

New Source Subcategory Limit	Discussion
TSM-Wet Biomass Stoker	Only one existing and one new wet stoker boiler has TSM compliance data. The new source data is below the 2013 new source limit.
TSM-Coal	Six of the 12 existing units with compliance data are below the 2013 limit for new sources. Of the ones that were above the limit, all of them were above both the 2013 limit and the remanded MACT floor emission limit. No new coal units were identified in recent compliance data.
PM-Suspension Burner	The calculated UPL is identical to the value calculated in the 2013 final rule for existing sources. However, the UPL calculation was less stringent than the new source performance standards (NSPS) limit for new boilers. Additionally, all of the 13 units with PM test data are below the 2013 limit for new sources.
PM-Dry Biomass Stoker	Of the seven units with PM test data, three units were below the 2013 emission limits for new sources, including one new dry biomass stoker boiler. Additionally, the UPL calculation was less stringent than the NSPS limit for new boilers.
PM-Coal	Of the 101 existing units with PM test data, nine units were below the 2013 emission limit for new sources. No new coal units were identified in recent compliance data.
CO-Dry Biomass Stoker	All seven of the existing units with data, including one new dry biomass stoker were below the 2013 limit.
CO-Coal Fluidized Bed with Heat Exchanger	The one existing unit with data was below the 2013 limit.

C. Revisions to Output-Based Emission Limits

The EPA reviewed the output-based emission limits, and revised as necessary, for subcategories and pollutants where the input-based emission limits were revised. There was not a corresponding revision in the output-based emission limit for certain subcategories and pollutants where the input-based emission limit was revised, due to rounding (*i.e.*, the input-based emission limit revision was small enough that performing the output-based calculations did not result in a different emission limit after rounding to two significant figures). We also updated the output-based emission limit calculations to use data from the current population of best performers, considering the changes to the rankings made in response to the court remands. Specifically, we revised the steam conversion factor (steam Btu out/fuel Btu in) used to calculate the output-based limits in the units of lb/MMBtu steam output for three subcategories for existing sources: biomass dutch oven, wet biomass, and coal stoker. We reviewed the corresponding steam conversion factors for new sources, but revisions were not necessary as a result of the new analyses. The memorandum, *Alternate Equivalent Output-Based Emission Limits for Boilers and Process Heaters Located at Major Source Facilities – 2019 Revision*, which is available in the docket for this action, provides details of the output-based emission limit revisions and methodology.

D. Proposed Response to the Amended Issue: CO as a Surrogate for Organic HAP

On July 29, 2016, the D.C. Circuit remanded to the EPA to address a public comment relating to the potential availability of alternative control technologies which reduce organic HAP without impacting CO emissions. In doing so, the court rejected challengers' argument that the EPA could not use CO as a surrogate for non-dioxin/furan (D/F) organic HAP and limited its remand to the Agency's failure to address evidence in the record on the potential availability of alternative control technologies. The court further noted that "it is likely" that the EPA would be able to adequately explain its use of CO on remand. *U.S. Sugar v. EPA*, 830 F.3d at 630.

It is helpful to provide some background on the EPA's decision to use CO as a surrogate in the Boiler MACT rule in order to provide the context for the EPA's action to address the *U.S. Sugar* court's remand for explanation. In the preamble to the June 2010 proposal, we presented the rationale for using CO as a surrogate for non-D/F organic HAP emitted from boilers and process heaters. We stated that CO has generally been used as a surrogate for organic HAP because CO is a good indicator of incomplete combustion and organic HAP are products of incomplete combustion. However, based on concerns that CO may not be an appropriate surrogate for D/F because, unlike other organic HAP, D/F can be formed outside the combustion unit, we proposed using CO as a surrogate only for non-D/F organic HAP. For non-D/F organic HAP, we concluded that using CO as a surrogate was a reasonable approach because minimizing CO emissions will result in minimizing non-D/F organic HAP. We stated that, for boilers and process heaters, methods used for the control of CO emissions would be the same methods used to control non-D/F organic HAP emissions. These emission control methods include achieving good combustion or using an oxidation catalyst. Standards limiting emissions of CO will also result in decreases in non-D/F organic HAP emissions (with the additional benefit of decreasing volatile organic compounds (VOC) emissions). Establishing emission limits for specific organic HAP would be impractical and costly. Thus, we concluded that CO, which is less expensive to test for and monitor, is appropriate for use as a surrogate for non-dioxin organic HAP.

We stated in the 2010 proposal that we recognized that the level and distribution of organic HAP will vary from unit to unit. For example, the principal organic HAP emitted from coal-fired units is benzene, which accounts for about 20 percent of the organic HAP with formaldehyde accounting for about 4 percent of the organic HAP. Whereas, the principal organic HAP emitted from biomass-fired units is formaldehyde, which accounts for 34 percent of the organic HAP with benzene accounting for about 25 percent of the organic HAP.[7] For oil-fired units, formaldehyde is the principal organic HAP, accounting for about 80 percent of the organic HAP. Limiting CO as a surrogate for only non-dioxin organic HAP would eliminate costs associated with speciating numerous compounds. We also stated that CO was preferable because many sources currently have CO continuous emission monitoring systems (CEMS).

In the 2013 final rule preamble, as part of the rationale for the 130 ppm CO minimum MACT floor level, we again explained the basis for concluding that CO is an appropriate surrogate. That is, CO is a conservative surrogate for organic HAP because organic HAP emissions are extremely low when sources operate under the good combustion conditions required to achieve low CO levels. There are myriad factors that affect combustion efficiency (CE) and, as a function of CE, CO emissions. As combustion conditions improve and hydrocarbon levels decrease, the larger and easier to combust compounds are oxidized to form smaller compounds that are, in turn, oxidized to form CO and water. As combustion continues, CO is then oxidized to form CO_2 and water. Because CO is a difficult to destroy refractory compound (*i.e.,* oxidation of CO to CO_2 is the slowest and last step in the oxidation of hydrocarbons), it is a conservative surrogate for destruction of hydrocarbons, including organic HAP.

Available control technologies for organic HAP emissions are of two types: combustion and recovery. The combustion devices include thermal incinerators, catalytic incinerators, flares, and boilers/process heaters. Applicable recovery devices include condensers, adsorbers, and

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[7] Based on emission factors reported on the EPA webpage, *AP 42, Fifth Edition, Volume 1—Chapter 1: External Combustion Sources,* located at *https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf*.

absorbers. The combustion devices are the more commonly applied control devices, since they are capable of high removal (*i.e.*, destruction) efficiencies for almost any type of organic vapor HAP.[8] As discussed below, the removal efficiencies of the recovery techniques generally depend on the physical and chemical characteristics of the organic HAP under consideration as well as the emission stream characteristics. Applicability of the control techniques depends on the individual emission stream under consideration. In this case, it would be emission streams from boilers and process heaters. The key emission stream characteristics and HAP characteristics that affect the applicability of each control technique are discussed below.

Thermal incinerators use combustion to control a wide variety of continuous organic HAP emission streams. Compared to the other techniques, thermal incineration is broadly applicable; that is, it is much less dependent on HAP characteristics and emission stream characteristics. Destruction efficiencies up to 99 percent or higher are achievable with thermal incineration. Thermal incineration typically is applied to emission streams that are dilute mixtures of organic HAP and air.

Catalytic incinerators are similar to thermal incinerators in design and operation except that they employ a catalyst to enhance the reaction rate. Since the catalyst allows the reaction to take place at lower temperatures, significant fuel savings may be possible with catalytic incineration. Catalytic incineration is not as broadly applicable as thermal incineration since performance of catalytic incinerators is more sensitive to pollutant characteristics and process conditions than is thermal incinerator performance. Materials in the emission stream can poison

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[8] *Handbook Control Technologies for Hazardous Air Pollutants*, EPA/625/6-91/014, June 1991, Center for Environmental Research Information, Office of Research and Development, U.S. EPA.

the catalyst and severely affect its performance. Destruction efficiencies of 95 percent of HAP can typically be achieved with catalytic incineration.

Flares are commonly used for disposal of waste gases during process upsets and emergencies. They are basically safety devices that are also used to destroy waste emission streams. Flares can be used for controlling almost any organic HAP emission stream.

Boilers or process heaters are used to control emission streams containing organic compounds. These are currently used as control devices for emission streams from several industries (*e.g*., refinery operations, polymers and resins operations, chemical reactor processes, and distillation operations, *etc*.) See 40 CFR part 63, subparts JJJ, OOO, and PPP. Typically, off-gases containing organic HAP emissions are controlled in boilers or process heaters and used as supplemental fuel if they have sufficient heating value. When used as emission control devices, boilers or process heaters can provide destruction efficiencies of greater than 98 percent.

Carbon adsorption is a recovery (non-combustion) technique commonly employed as a pollution control and/or a solvent recovery technique. It is applied to dilute mixtures of HAP and air. Removal efficiencies of 95 to 99 percent can be achieved using carbon adsorption. Outlet concentrations around 50 parts per million by volume (ppmv) can be routinely achieved with state-of-the-art systems; concentrations as low as 10 to 20 ppmv can be achieved with some compounds. Highly volatile materials (*i.e*., molecular weight less than about 45) do not adsorb readily on carbon; therefore, adsorption is not typically used for controlling emission streams containing such compounds. Carbon adsorption is also relatively sensitive to emission stream conditions, such as high humidity and temperatures.

Absorption is widely used as a raw material and/or a product recovery technique in separation and purification of gaseous streams containing high concentrations of VOC. As an emission control technique, it is much more commonly employed for inorganic vapors than for organic vapors. Using absorption as the primary control technique for organic vapor HAP is subject to several limitations and problems. The suitability of absorption for controlling organic vapor emissions is determined by several factors; most of these factors will depend on the specific HAP in question. For example, the most important factor is the availability of a suitable solvent. The pollutant in question should be readily soluble in the solvent for effective absorption rates.

Condensers are widely used as raw material and/or product recovery devices. They are frequently applied as preliminary air pollution control devices for removing VOC contaminants from emission streams prior to other control devices such as incinerators, adsorbers, or absorbers. Condensers are also used by themselves for controlling emission streams containing high VOC concentrations (usually >5,000 ppmv). In these cases, removal efficiencies obtained by condensers can range from 50 to 90 percent although removal efficiencies at the higher end of the scale usually require HAP concentrations of around 10,000 ppmv or greater. Therefore, it is not possible for condensation with water as the coolant to achieve the low outlet concentrations that would be required in HAP control applications.

In summary, combustion is the more commonly applied technology for controlling organic HAP since it is capable of high removal efficiencies for organic HAP and its effectiveness does not depend on the makeup of the organic HAP stream or the organic HAP concentration. In fact, the devices regulated by the rule (boilers and process heaters) not only combust fuel for producing steam and/or process heat but serve a dual function in that they also effectively control organic HAP when good combustion conditions are present. Recovery (non-combustion) devices are not applicable on all organic HAP and are not effective on low organic

HAP concentration streams. Also, recovery devices' effectiveness is dependent on an emission stream with a high organic HAP content (>250 ppmv), compared to the organic HAP content of the emission streams from boilers which are around 1 ppmv for fossil fuels (coal and oil) and around 10 ppmv for biomass.[9] Therefore, at the organic HAP levels generated and emitted from a boiler, the recovery (non-combustion) technologies would be ineffective. Furthermore, none of the best performing units employ any add-on alternative control device for controlling organic HAP. Many industrial boilers and process heaters employ post combustion controls for PM, acid gases, and/or Hg but these add-on controls do not affect emissions of CO or non-dioxin organic HAP.

For these reasons, we continue to conclude that the level of CO emissions, which indicates organic HAP reductions achieved through the use of combustion controls, is an appropriate surrogate for controlling organic HAP emissions from boilers and process heaters.

E. Proposed Response to the Amended Issue: CO 130 PPM Threshold Emission Limits

The D.C. Circuit, on March 16, 2018, issued an opinion in the Boiler MACT reconsideration case, *Sierra Club v. EPA*, 884 F.3d 1185, which was a petition for review by environmental groups of the 2015 reconsideration of the Boiler MACT rule. The case addressed two issues that were severed from the litigation challenging the 2013 Boiler MACT rule (*U.S. Sugar v. EPA*): (1) the 130-ppm threshold for CO standards, which, as described above, were established as a surrogate for non-dioxin organic HAP and (2) the definitions of periods of startup and shutdown and the applicable work practices to be used during those periods. The

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[9] Based on emission factors reported on the EPA webpage, *AP 42, Fifth Edition, Volume 1—Chapter 1: External Combustion Sources*, located at *https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf*.

court granted the petition as to the CO issue, finding that the EPA had not provided sufficient record support for the CO concentration threshold and remanded for further explanation, but denied the petition on the startup/shutdown issue and upheld the EPA's approach as consistent with the CAA.

The court declined to revisit its opinion in *U.S. Sugar*, in which the court upheld the use of CO as a surrogate for organic HAP but remanded to the EPA to address whether there are means to reduce organic HAP other than by combustion. Against that backdrop, the court, in its decision in *Sierra Club* said the question before it was whether, assuming CO is an appropriate surrogate, the EPA's decision to establish a 130-ppm threshold as the lowest (*i.e.*, most stringent) numeric CO limit was consistent with the requirements of the CAA. Based on a close examination of the record, the court held that the EPA had not sufficiently explained its rationale and questioned EPA's reliance on data regarding the relationship between formaldehyde and organic HAP that the EPA had previously characterized as unreliable.

The court did note that if the EPA made and adequately supported a determination that no further reduction of HAP would occur once CO levels had been reduced to 130 ppm, the threshold would be appropriate and consistent with the CAA. The court noted three specific issues it believed the Agency did not adequately address: (1) the EPA gave no reason why organic HAP emissions could not be further reduced, once CO emissions reach 130 ppm, (2) the EPA relied on formaldehyde data to support its conclusion but elsewhere stated that the same data were not a reliable indicator of organic HAP emissions at very low levels, and (3) the EPA did not adequately explain if there is a non-zero CO level below which organic HAP levels cannot be further reduced, why 130 ppm is the appropriate level. Responses to these three issues are addressed below.

In the January 31, 2013, final rule, we revised the CO emission limit for several subcategories, both new and existing, to reflect a CO level that, we stated, is consistent with MACT for organic HAP reduction. The revision was brought about by several commenters who recommended that the EPA evaluate a minimum CO standard (*i.e.*, 100 ppm corrected to 7-percent oxygen[10]) to serve as a lower bound surrogate for organic HAP. The commenters also provided data and information to support such a standard and noted that the EPA has taken a similar approach in other emission standards under CAA section 112. See 40 CFR part 63, subpart EEE (NESHAP for Hazardous Waste Combustors).

In the preamble to the 2013 final rule, we stated that we evaluated whether there is a minimum CO level for boilers and process heaters below which there is no further benefit in organic HAP reduction/destruction. Specifically, we evaluated the relationship between CO and formaldehyde using the available data obtained during the rulemaking. Formaldehyde was selected as the basis of the organic HAP comparison because it is the most prevalent organic HAP in the emission database and many paired tests existed for boilers and process heaters for CO and formaldehyde and because formaldehyde was the only organic HAP for which we had such data. The paired data show decreasing formaldehyde emissions with decreasing CO emissions down to CO levels around 300 ppm (with formaldehyde emissions down to less than 1 ppm), supporting the selection of CO as a surrogate for organic HAP emissions. A slight increase in formaldehyde emissions, to between 1 and 2 ppm, was observed at CO levels below around 200 ppm, suggesting a breakdown in the CO-formaldehyde relationship at low CO concentrations. At levels lower than 150 ppm, the mean levels of formaldehyde appeared to

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[10] The CO emission standards in the 2013 final rule are corrected to 3-percent oxygen. The 130 ppm CO standards in the 2013 final rule is equivalent to 100 ppm corrected to 7-percent oxygen.

increase, as does the overall maximum value of and variability in formaldehyde emissions. However, at that time, we were not aware of any reason why formaldehyde concentrations would increase as CO concentrations continue to decrease, indicating improved combustion conditions. Our thinking at the time was that imprecise formaldehyde measurements at low concentrations (*i.e.*, 1–2 ppm) may have accounted for this slight increase in formaldehyde emissions observed at CO levels below 130 ppm.

In the preamble of the 2013 final rule, we stated, “Based on this, we do not believe that such measurements are sufficiently reliable to use as a basis for establishing an emissions limit.” See 78 FR 7145. In that statement, we were referring to the formaldehyde measurements and, thus, to the decision to set a CO standard instead of a formaldehyde standard. Based on that analysis, we promulgated a minimum MACT floor level for CO of 130 ppm corrected to 3-percent oxygen (which is equivalent to 100 ppm corrected to 7-percent oxygen). We noted this was the same approach used to establish the CO emission limit of 100 ppm corrected to 7-percent oxygen for the Burning of Hazardous Waste in Boilers and Industrial Furnaces final rule (56 FR 7134, February 21, 1991). In that rulemaking, the EPA chose the 100-ppm (corrected to 7-percent oxygen) limit because the research indicated that while CO was a good surrogate for the destruction of organic HAP, the validity of that surrogacy was questionable at CO levels of approximately 400 ppm and below. Based on the EPA’s authority under the Resource Conservation and Recovery Act to establish standards that are protective of human health and the environment, the Agency established the 100-ppm standard. The EPA later established the 100-ppm corrected to 7-percent oxygen standard as the MACT standard for hazardous waste combustors (see 70 FR 59462) and explained why that standard was an appropriate floor (see 69 FR at 21282).

The trend that our CO – formaldehyde data present has also been observed in a study[11] done on polycyclic aromatic hydrocarbons (PAH) emissions from coal combustion. PAH constitute a group of organic HAP. The study presents a graph of PAH vs. excess oxygen[12] which shows that at the lowest percentage of excess oxygen (5 percent), the highest PAH amount (0.25 ppm) is measured and shows minimum PAH emissions (0.02 ppm) at 20-percent excess oxygen. The graph further shows that as the excess oxygen level increases above 20 percent, higher PAH emissions (about 0.06 ppm at 40 percent excess air) are observed. The study does not present corresponding CO values. However, the study does provide information showing that CO emissions continue to decrease with increasing excess oxygen levels above 20 percent, as indicated by the increased combustion efficiencies reported in the study for excess oxygen over the range of 5 to 40 percent. Combustion efficiency (CE) is a measure of the completeness of oxidation of all fuel (organic) compounds and is determine by the CE Formula: $CE = [CO_2 /(CO_2 + CO)] \times 100$.[13] Thus, CE increases with decreasing CO levels.

The PAH study does provide a possible explanation for this phenomenon. In order to assess the PAH emissions as a function of combustion variables, the first aim of the study was to reach maximum CE. The study stated that "it can be assumed that the emissions due to bad combustion have practically been eliminated, and so the data obtained will be due to the

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[11] *Organic Atmospheric Pollutants: Polycyclic Hydrocarbons from Coal Atmospheric Fluidised Bed Combustion (AFBC)*, A.M Mastral, M.S. Callen, R. Murillo, and T. Garcia, Instituto de Carboquimica, 1999.

[12] Excess oxygen, or excess air, is commonly used to define combustion. The excess oxygen is the amount of oxygen in the incoming air not used during combustion. Inadequate excess oxygen results in unburned combustibles (fuel and CO), while too much excess oxygen results in increased flue gas flow and decreased temperature and residence time for combustion.

[13] CE formula and calculator, *https://ncalculators.com/environmental/combustion-efficiency-calculator.htm.*

combustion process." The study states that at the lowest percentages of excess oxygen, the interaction between oxygen and radicals should be less favored and, as a result, the PAH amount would be higher. At the highest percentages of excess oxygen possible, interaction with PAH seemed to be minimized due to the higher gas velocities shortening the contact resulting in increasing PAH emissions.

Furthermore, the EPA's Office of Research and Development (ORD), in support of the NESHAP from Coal- and Oil-Fired Electric Utility Steam Generating Units (also known as the Mercury and Air Toxics Standards or MATS), conducted a series of tests in the Agency's Multipollutant Control Research Facility (MPCRF). As part of these tests, potential surrogate relationships were examined for various non-D/F organic HAP. The objective of the testing program was to collect selected HAP emission data while firing coals under varied test conditions and evaluate relationships between those concentrations and other process concentrations and/or conditions. One of the principal objectives was to measure concentrations of non-D/F organic HAP and compare to the emission of candidate surrogates (*e.g.*, CO, total hydrocarbons, *etc.*)[14] Several organic HAP, discussed below and presented as figures in the study's final report, were quantified from multiple tests with CO concentrations and show a similar trend.

Figure 4-16 of the MPCRF study shows the concentration of phenol, an organic HAP, plotted against concentration of CO. CO concentrations ranged from 40 to 140 ppm, at 7-percent oxygen, with phenol concentrations ranging from 0.6 parts per billion (ppb) at 40 ppm CO to 1

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[14] Surrogacy Testing in the MPCRF, Prepared for U.S. EPA, Prepared by ARCADIS, March 30, 2011. See Docket ID Item No. EPA-HQ-OAR-2002-0058-3942.

ppb at 140-ppm CO with the lowest phenol concentration (0.5 ppb) measured at 95-ppm CO (120-ppm CO at 3-percent oxygen).

The MPCRF study also examined formaldehyde emissions against CO concentrations. The five data points (Figure 4-17 of the study) are all for CO concentrations below 70 ppm with the lowest formaldehyde emissions (10 ppb) measured at 70-ppm CO and with higher formaldehyde emissions (57 ppb) measured at a lower CO level of 40-ppm CO.

In addition, the MPCRF study shows similar results for chloroform (another organic HAP). The five data points (Figure 4-24 of the study) show chloroform emissions of 0.038 ppb at 170-ppm CO at 3-percent oxygen, 0.025 ppb chloroform at 130-ppm CO at 3-percent oxygen, and 0.054 ppb chloroform at 40-ppm CO at 3-percent oxygen.

The MPCRF does not present any explanation on why these trends were observed. One of the goals of the MPCRF testing was to determine or demonstrate a relationship between concentrations of organic compounds and combustion conditions. However, due to low emission levels, non-detects, and other complexities, the key conclusion drawn was that the testing did not disprove an expected relationship between organic concentrations and combustion conditions.

There are myriad factors that affect CE and, as a function of CE, CO emissions. As combustion conditions improve and hydrocarbon levels decrease, the larger and easier to combust compounds are oxidized to form smaller compounds that are, in turn, oxidized to form CO and water. As combustion continues, CO is then oxidized to form CO_2 and water. Because CO is a difficult to destroy refractory compound (*i.e.,* oxidation of CO to CO_2 is the slowest and last step in the oxidation of hydrocarbons), it has been considered a conservative surrogate for destruction of hydrocarbons, including organic HAP.

Neither the PAH study nor the MPCRF study provide an explanation for the phenomenon observed in these studies. In trying to explain why this phenomenon occurs, we know that combustion is the chemical reaction of oxygen with combustible compounds (*e.g.*, organics) and that time, temperature, and turbulence impact the speed and completeness of the combustion reaction. For complete combustion, the oxygen must come into intimate contact with the combustible molecule at sufficient temperature, and for a sufficient length of time, in order to complete the reaction. Two factors that affect reaction rates are the concentration of the reactants (oxygen and organic HAP) and the temperature of the reactants. Every combustible substance has a minimum ignition temperature, which must be attained or exceeded, in the presence of oxygen, if combustion is to ensue under the given conditions. Lower concentrations will produce a decrease in the rate of reaction and a decrease in the temperature will decrease rate of reaction. As more ambient temperature combustion air (oxygen) is added, the concentration and temperature of the reactant (organic HAP) is reduced. Thus, a potential explanation is that with the increased combustion air (oxygen), the resulting increased turbulence, while providing increased mixing, can result in more organic molecules being forced near the furnace walls, which are cold compared to the combustion zone. This can essentially slow down or quench the combustion reactions by cooling the molecules of the organic compounds to below their minimum ignition temperature. Thus, those organic HAP molecules would not be combusted and would be emitted unchanged. Any action having the effect of decreasing the reaction rate of the organic HAP will consequently result in less organic HAP being combusted and, thus, higher organic HAP emissions being observed and appear to be an increase, at higher excess oxygen (and lower CO emissions) levels.

The range of the formaldehyde measurements for the reported paired formaldehyde-CO emissions data for the 97 emission units is 0.00009 ppm (0.09 ppb) to 2.0 ppm. The mathematical average of the corresponding CO emissions from the best performing 12 percent of units, identified as those units with the lowest formaldehyde emissions, is 137 ppm.

At the time of the 2013 rulemaking, we observed that reducing CO emissions also resulted in a reduction of organic HAP emissions until a leveling off in organic HAP reduction is reached after which further reduction of CO levels appeared to result in higher levels of organic HAP emitted. Our determination that setting a CO standard below a CO level of 130 ppm would result in no additional organic HAP reduction is supported by both the independent PAH emission study and the MPCRF study which both show similar trends. That is, organic HAP levels decreased with decreasing CO levels until a leveling off and trending upward with further decreasing CO levels. Also, based on the level of the organic HAP emissions measured in the two studies, we do not consider the formaldehyde data used in our establishment of the 130 ppm CO standard to have been imprecise and, thus, unreliable. The formaldehyde data measured at CO levels below 130 ppm reflect the variability (scatter) of organic HAP emissions when each data point is from a different unit. Whereas, the organic HAP emission results presented in the two studies, which were measured at similar low concentrations, are from tests conducted on a single unit at varying CO levels.

The seven subcategories with the 130 ppm CO level in the 2013 final rule are: (1) Pulverized Coal Boilers; (2) Coal Stokers; (3) Coal Fluidized Bed; (4) Heavy Liquid Fuel; (5) Light Liquid Fuel; (6) Non-Continental Liquid; and (7) Process Gas. Based on our review of the data in 2013, we established that a CO emission level of 130 ppm represented MACT for controlling organic HAP emissions for units in the six subcategories. Based on additional information obtained during and after the rulemaking, as discussed above, we reaffirm our conclusion that a 130-ppm CO concentration threshold represents MACT for organic HAP for the six subcategories.

IV. Results and Proposed Decisions

A. What are the resulting changes to emission limits?

Based on all of the revisions made to address the remand related to ranking and assessing co-fired units in the MACT floor calculations, the changes made for UPL calculations for small datasets, and the decisions to propose certain limits as beyond-the-floor limits, there are 34 different emission limits that we are proposing to change. The detailed list of revisions to unit rankings and revised MACT floor calculations are presented in the docketed memorandum, *Revised MACT Floor Analysis (2019) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source.* Of these 34 emission limits, 28 of the limits are more stringent than the corresponding limits in the 2013 final rule. Six of the limits are modestly less stringent, with no more than a 25-percent increase. The proposed and corresponding current limits are shown in Table 6.

TABLE 6. SUMMARY OF CHANGES TO EMISSION LIMITS IN THE PROPOSED ACTION

Subcategory	Pollutant	Current Emission Limit (lb/MMBtu of heat input or ppm at 3-percent oxygen for CO)	Proposed Emission Limit (lb/MMBtu of heat input or ppm at 3-percent oxygen for CO)
New-Solid	HCl	2.2E-02	3.0E-04
New-Dry Biomass Stoker	TSM8	4.0E-03	5.0E-03
New-Biomass Fluidized Bed	CO	230	130

New-Biomass Fluidized Bed	PM (TSM)	9.8E-03 (8.3E-05)	4.1E-03 (8.4E-06)
New-Biomass Suspension Burner	CO	2,400	220
New-Biomass Suspension Burner	TSM	6.5E-03	8.0E-03
New-Biomass Hybrid Suspension Grate	CO	1,100	180
New-Biomass Dutch Oven/Pile Burner	PM	3.2E-03	2.5E-03
New-Biomass Fuel Cell	PM	2.0E-02	1.1E-02
New-Wet Biomass Stoker	CO	620	590
New-Wet Biomass Stoker	PM	0.03	0.013
New-Liquid	HCl	4.4E-04	7.0E-05
New-Heavy Liquid	PM (TSM)	1.3E-02 (7.5E-05)	1.9E-03 (6.4E-06)
New-Process Gas	PM	6.7E-03	7.3E-03
Existing-Solid	HCl	2.2E-02	2.0E-02
Existing-Solid	Hg	5.7E-06	5.4E-06
Existing-Coal	PM	4.0E-02	3.9E-02
Existing-Coal Stoker	CO	160	150
Existing-Dry Biomass Stoker	TSM	4.0E-03	5.0E-03
Existing-Wet Biomass Stoker	CO	1,500	1,100
Existing-Wet Biomass Stoker	PM (TSM)	3.7E-02 (2.4E-04)	3.4E-02 (2.0E-04)
Existing-Biomass Fluidized Bed	CO	470	210
Existing-Biomass Fluidized Bed	PM (TSM)	1.1E-01 (1.2E-03)	2.1E-02 (6.4E-05)
Existing-Biomass Suspension Burners	PM (TSM)	5.1E-02 (6.5E-03)	4.1E-02 (8.0E-03)

Existing-Biomass Dutch Oven/Pile Burner	PM	2.8E-01	1.8E-01
Existing-Liquid	Hg	2.0E-06	7.3E-07
Existing-Heavy Liquid	PM	6.2E-02	5.9E-02
Existing-Non-Continental Liquid	PM	2.7E-01	2.2E-01
Existing-Process Gas	PM	6.7E-03	7.3E-03

The EPA requests comment on the revisions to the emission limits in light of the changes the EPA has proposed in response to the remand. Broader comments with respect to the UPL calculation methodology will not be considered within the scope of this rulemaking. The EPA will only consider data that is already available in the rulemaking record. The EPA also requests comments on its determination of beyond-the-floor emission limits for certain subcategories. The emission reduction impacts associated with these changes to the MACT floor emission limits are discussed in the docketed memorandum *Revised (2019) Methodology for Estimating Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants.*

B. What compliance dates are we proposing?

The EPA is proposing that facilities have up to 3 years after the effective date of the final rule to comply with the new emissions limits in the final rule. Before this date, facilities must continue to comply with the rule as it was finalized in 2015. This allowance is being made considering that some facilities may require additional add-on controls or monitoring equipment to be designed, purchased, and installed in order to meet the more stringent emission limits, or to modify the method of compliance based on the changes in emission limits. In addition, units will require lead time to prepare and execute their testing plans to demonstrate compliance with the updated emission limits and to update reports to incorporate the revised emission limits. The EPA requests comment on this time frame.

C. What other actions are we proposing?

We are proposing several technical corrections. These amendments are being proposed to correct inadvertent errors that were promulgated in the final rule. We are soliciting comment only on whether the proposed changes provide the intended accuracy, clarity, and consistency. These proposed changes are described in Table 7 of this preamble. We request comment on all these proposed changes.

TABLE 7. MISCELLANEOUS PROPOSED TECHNICAL CORRECTIONS TO 40 CFR PART 63, SUBPART DDDDD

Section of subpart DDDDD	Description of proposed correction
40 CFR 63.7500(a)	Revise this paragraph to remove the comma after “paragraphs (b).”
40 CFR 63.7521(c)(1)(ii)	Revise this paragraph to remove the requirement to collect samples during the test period at 1-hour intervals.
40 CFR 63.7530(b)(4)(iii)	Revise this paragraph to remove the sentence regarding establishing the pH operating limit because establishing the pH operating limit is not required for a PM wet scrubber.
40 CFR 63.7540(a)(9)	Revise this paragraph to clarify that “certify” is intended to apply only to PM CEMS, not PM continuous parameter monitoring systems (CPMS) because PM CPMS do not have a performance specification.
40 CFR 63.7575	Revise the definition of “Other gas 1 fuel” to clarify that it is the maximum Hg concentration of 40 micrograms/cubic meter of gas.

	Add definition of "12-month rolling average" to clarify that the previous 12 months must be consecutive but not necessarily continuous. Revise paragraph (4) of definition "Steam output" to correct "heaters" to "headers."
Table 1 to subpart DDDDD	Revise the output limit in item 8.a to correct for a rounding error, the value is now 4.3E-01 lb per MMBtu instead of 4.2E-01 lb per MMBtu.
Table 7 to subpart DDDDD	Revise footnote "b" to clarify that when multiple performance tests are conducted, the maximum operating load is the lower of the maximum values established during the performance tests.
Table 8 to subpart DDDDD	Revise item 8.d to clarify that the correct equations to use are Equations 7, 8, and/or 9 in 40 CFR 63.7530.

V. Summary of Cost, Environmental, and Economic Impacts

A. What are the affected sources?

As mentioned previously, this rule affects a wide range of facilities in the ICI sector that are located at major sources of HAP and have a boiler or process heater as defined in the final rule. The 2013 Emission Database for Boilers and Process Heaters estimated there were approximately 14,000 existing boilers and process heaters currently operating at 1,702 different facilities that are major sources of HAP and subject to the Boiler MACT. The vast majority of these combustion units (nearly 12,000 units) were gas-fired and in the Gas 1 subcategory, which are subject to the rule but are not subject to numeric emission limits. Another 472 units were small or limited use and were also not subject to numeric emission limits. By contrast, the EPA has reviewed compliance data submitted to CEDRI and WebFIRE and the trade association Council of Industrial Boilers, which had provided input on units that had shutdown or switched to natural gas fuel as part of its compliance strategy. The EPA then compiled an updated estimate of units that are subject to emission limits. These data show 533 existing boilers and process heaters, of which 443 remain operational and belong in one of the subcategories that are subject to numeric emission limits. This count excludes any boilers that are no longer operational, boilers that have refueled and switched to the natural gas subcategory and are, therefore, no longer impacted by changes to emission limits, or boilers that are classified as small or limited use.

For new sources, the EPA had projected new sources anticipated to be built by 2015 from a baseline year of 2008.[15] While the projections had anticipated correctly that the only new units subject to emission limits would be new large biomass units, the actual number of new units is significantly lower than projected in the January 2013 final rule. The CEDRI and WebFIRE compliance data provided updates on eight new biomass units that are subject to emission limits and reporting compliance data. Since new units have had to comply since April 2013, these eight units reflect a new unit rate of 1.3 new units per year during the 6-year period of April 2013 through April 2019. Using these new source data, the EPA estimates that, four more biomass boilers or process heaters are expected to be constructed over the next 3 years. As such, 12 new boilers and process heaters are estimated to be affected by the proposed amendments.

Table 8 presents a summary table comparing the number of existing and new affected sources, by subcategory. The counts exclude small or limited use units.

TABLE 8. SUMMARY OF CHANGES TO NUMBER OF AFFECTED SOURCES

Subcategory	Estimate of Sources in 2013 Final Rule	Estimate of Sources in 2019 Proposal

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[15] See docketed memorandum: *Revised New Unit Analysis Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source*. November 2011. Docket ID Item No. EPA-HQ-OAR-2002-0058-3388.

Existing-Biomass	481	285
Existing-Coal	606	124
Existing-Heavy Liquid	291	6
Existing-Light Liquid	260	24
Existing-Non-Continental Liquid	19	5
Existing-Process Gas	78	0
New-Biomass	78 (projected online by 2015)	8 (actual) + 4 (projected)
New-Coal	0	0
New-Heavy Liquid	0	0
New-Light Liquid	0	0
New-Non-Continental Liquid	0	0
New-Process Gas	0	0

B. What are the air quality impacts?

Table 9 of this preamble illustrates, for each basic fuel subcategory, the incremental emissions reductions that would be achieved by the proposed amendments. The reductions are all additional to the reductions accounted for in the January 2013 final rule for both new and existing sources. Nationwide emissions of selected HAP (*i.e.*, HCl, hydrogen fluoride, Hg, metals) would be reduced by an additional 37.35 tpy as compared to the estimates in the January 2013 final rule. This additional decrease is due mainly to changes to certain emission limits that are anticipated to achieve additional reductions. The proposed amendments are expected to result in an additional 34 tpy of reductions in HCl emissions. The proposed amendments are also expected to have a modest effect on Hg, with an estimated additional reduction of 3.96 lbs per year. Emissions of filterable PM would decrease by 333 tpy, of which 251 tpy is $PM_{2.5}$, due to the proposed amendments. Emissions of non-Hg metals (*i.e.*, antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium) would decrease by 2.3 tpy. In addition, the proposed amendments are estimated to result in an additional 393 tpy of reductions in SO_2 emissions. A discussion of the methodology used to estimate emissions, emissions reductions, and incremental emission reductions is presented in the memorandum, *Revised (2019) Methodology for Estimating Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants*, which is available in the docket for this action.

TABLE 9. SUMMARY OF TOTAL EMISSIONS REDUCTIONS FOR THE PROPOSED RULE (TONS/YR)

Source	Subcategory	HCl	PM	Non-Hg Metals[1]	Hg
Exiting Units	Coal	9.8	0	0	1.88E-03
	Biomass	14.5	333	2.3	1.79E-04
New Units	Biomass	9.8	0	0	0

[1] Antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

C. What are the cost impacts?

We estimated the total capital costs of the proposed amendments to be about $83 million and the total annualized costs to be about $22 million in 2016 dollars. The total capital and annual costs include costs for control devices, testing, and monitoring associated with the changes to the emission limits. These costs are incremental to the costs presented in the January 2013 final rule in the sense that they show where units with compliance data must install add-on controls or modify compliance strategies in order to meet the more stringent limits in this proposal. Table 10 of this preamble shows the total capital and annual cost impacts of the proposed rule for each subcategory. The cost methodology and results are documented in the memorandum, *Revised (2019) Methodology for Estimating Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants*, which is available in the docket for this action.

TABLE 10. SUMMARY OF TOTAL CAPITAL AND ANNUAL COSTS FOR NEW AND EXISTING SOURCES FOR THE PROPOSED RULE (2016$)

Source	Subcategory	Estimated/ Projected No. of Affected Units	Capital Costs (10^6 $)	Testing and Monitoring Annualized Costs (10^6 $/yr)	Annualized Cost (10^6 $/yr)
Existing Units	Coal	2	0.803	0.006	0.327
	Biomass	26	81.1	0.267	20.5
New Units	Solid units (all biomass)	5	0.952	0.017	0.653

In addition, another way to present compliance costs is the PV. A PV is an estimate of costs that is a discounted stream of the annualized costs for the proposal calculated for the present day. The PV in 2016 of the costs is $103.7 million at a discount rate of 7 percent and $128.1 million at 3 percent. Calculated as an EAV, which is consistent with the PV of costs in 2016, the costs are $17.4 million at a discount rate of 7 percent and $18.3 million at a discount rate of 3 percent. These estimates are also in 2016 dollars. More information on the PV and EAV estimates can be found in the RIA for this proposal that is in the docket for this action.

D. What are the secondary impacts?

The EPA estimated the additional water usage that would result from installing wet scrubbers to meet the proposed amended emission limits for HCl would be 0.64 million gallons per year for new and existing sources compared to the current baseline. In addition to the increased water usage, an additional 0.27 million gallons per year of wastewater would be produced for new and existing sources. The annual costs of treating the additional wastewater are approximately $1,830. These additional costs are accounted for in the control cost estimates.

The EPA estimated the additional solid waste that would result due to the proposed amendments to be 1,550 tpy for new and existing sources. Solid waste is generated from flyash and dust captured in fabric filters and electrostatic precipitators (ESP) installed for PM and Hg controls as well as from spent materials from wet scrubbers and sorbent injection systems installed for additional HCl controls. The costs of handling the additional solid waste generated are $74,100. These costs are also accounted for in the control costs estimates.

The EPA estimated the proposed amendments would result in an increase of about 29.5 million kilowatts per year in national energy usage from the electricity required to operate control devices, such as wet scrubbers, ESPs, and fabric filters which are expected to be installed to meet the proposed rule. This energy requirement is estimated to result in an increase of approximately 17,740 tpy CO_2 based on emissions related to additional energy consumption.

A discussion of the methodology used to estimate impacts is presented in the *Revised (2019) Methodology for Estimating Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants*, which is available in the docket for this action.

E. What are the economic impacts?

The EPA conducted an economic impact analysis for this proposal, as detailed in the *Regulatory Impact Analysis for the Proposed ICI Boilers NESHAP Reconsideration*, which is available in the docket for this action. The economic impacts of the proposal are calculated as the percentage of total annualized costs incurred by affected parent owners to their annual revenues.

This ratio of total annualized costs to annual revenues provides a measure of the direct economic impact to parent owners of affected facilities while presuming no passthrough of costs to consumers of output produced by these facilities. We estimate that none of the 26 parent owners affected by this proposal will incur total annualized costs of 0.70 percent or greater of their revenues. Thus, these economic impacts are quite low for the affected companies and the multiple affected industries, and consumers of affected output should experience minimal price changes.

F. What are the benefits?

The EPA reports the estimated impact on health benefits from changes in $PM_{2.5}$ and SO_2 emissions. The estimated health co-benefits are the monetized value of the human health benefits among populations exposed to changes in $PM_{2.5}$. These benefits are co-benefits in this analysis since these pollutants are not targeted for control by this proposal. This rule is expected to alter the emissions of $PM_{2.5}$ (and SO_2). Due to the small change in emissions expected, we used the "benefit per ton" (BPT) approach to estimate the benefits of this rulemaking. The EPA has applied this approach in several previous RIAs[16] in which the economic value of human health impacts are derived at the national level based on previously established source-receptor relationships from photochemical air quality modeling.[17] These BPT estimates provide the total monetized human health benefits (the sum of premature mortality and premature morbidity) of

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[16] U.S. EPA. *Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States*. June 2011; *Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards*, December 2011; and *Regulatory Impact Analysis for the Particulate Matter National Ambient Air Quality Standards*; December- 2012.

[17] Fann N, Fulcher CM, Hubbell BJ. The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution. Air Qual Atmos Health. 2009;2(3):169-176. doi:10.1007/s11869-009-0044-0.

reducing 1 ton of $PM_{2.5}$ (or $PM_{2.5}$ precursor such as nitrogen oxide or SO_2) from a specified source. Specifically, in this analysis, we multiplied the estimates from the "Industrial Point Sources" sector by the corresponding emission reductions. This assumes that the emissions reductions from this proposed rule for industrial boilers scale linearly with the BPT Industrial Point Sources sector. The method used to derive these estimates is described in the Technical Support Document on estimating the BPT of reducing $PM_{2.5}$ and its precursors from 17 sectors.[18] One limitation of using the BPT approach is an inability to provide estimates of the health benefits associated with exposure to HAP (HCl, for example), CO, nitrogen dioxide, or ozone. The photochemical modeled emissions of the industrial point source sector-attributable $PM_{2.5}$ concentrations used to derive the BPT values may not match the change in air quality resulting from the emissions controls. The $PM_{2.5}$ emission reductions resulting from this rule are approximately 0.4 percent of the $PM_{2.5}$ annual emissions and 0.04 percent of the SO_2 emissions attributable to the BPT Industrial Point Sources. For this reason, the health co-benefits reported in Table 11 may be larger, or smaller, than those realized through this rule. We are taking comment on the modeling assumptions behind the benefits analysis results mentioned above as well as the utility of performing full-form (*i.e.*, full-scale) photochemical modeling for the final rule.

Table 11 summarizes the monetized PM-related health benefits per ton or reducing precursor pollutant emissions, using discount rates of 3 percent and 7 percent.

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[18] U.S. EPA, Technical Support Document. *Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from 17 Sectors*. February 2018.

TABLE 11. ESTIMATED $PM_{2.5}$-RELATED BENEFITS PER TON OF PROPOSED ICI BOILERS AND PROCESS HEATERS MACT RECONSIDERATION

Epidemiologic study used to quantify PM-related premature deaths				
Pollutant	Krewski et al. (2009)		Lepeule et al. (2012)	
	BPT (3-percent discount rate)	BPT (7-percent discount rate)	BPT (3-percent discount rate)	BPT (7-percent discount rate)
$PM_{2.5}$	$330,000	$300,000	790,000	$690,000
SO_2	$52,000	$47,000	$120,000	$100,000

Table 12 summarizes the range of estimated benefits by pollutant for the two BPT estimates at discount rates of 3 percent and 7 percent.

TABLE 12. ESTIMATED $PM_{2.5}$-RELATED HEALTH BENEFITS OF PROPOSED ICI BOILERS AND PROCESS HEATERS MACT RECONSIDERATION

Epidemiologic study used to quantify PM and SO_2-related premature deaths				
Pollutant	Krewski et al. (2009)		Lepeule et al. (2012)	
$PM_{2.5}$	Benefits (millions of 2016$, 3-percent discount rate)	Benefits (millions of 2016$, 7-percent discount rate)	Benefits (millions of 2016$, 3-percent discount rate)	Benefits (millions of 2016$, 7-percent discount rate)
	$84	$76	$200	$170
SO_2	$21	$19	$49	$40
Total	$110	$95	$250	$210

All BPT estimates have inherent limitations. Specifically, all national-average BPT estimates reflect the geographic distribution of the modeled emissions, which may not exactly match the emission reductions in this rulemaking, and they may not reflect local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors for any specific location. The photochemical modeled emissions of the industrial point source sector-attributable $PM_{2.5}$ concentrations used to derive the BPT values may not match well the change in air quality resulting from the emissions controls. For this reason, the health benefits reported here may be larger, or smaller, than those realized by this rule.

There are also climate disbenefits from the increase in CO_2 emissions that result from the increase in national energy use from control device operation. The disbenefits are $0.09 million at a 3-percent discount rate and $0.01 million at a 7-percent discount rate. These calculations reflect the domestic social cost of carbon for CO_2 for 2025, the year for which benefits are estimated that is an approximation for 2023, the year of full rule compliance. These disbenefits are included in the estimates of benefits and net benefits for this proposal.

The benefit analysis for this proposal is detailed in the *Regulatory Impact Analysis for the Proposed ICI Boilers and Process Heaters NESHAP Reconsideration*, which is available in the docket for this action.

VI. Request for Comments

The EPA is seeking comments on the issues raised in this proposal. It will not respond to comments addressing any other issues. Specifically, the EPA is seeking comments on the revised MACT floor emission limit calculations, including any comments or corrections to the underlying data used to compute those emission limits, the selection of beyond-the-floor limits for certain subcategories. The EPA is also seeking input on the inventory of units used to quantify the impacts of these proposed amendments, which relied on real compliance data submitted to CEDRI and WebFIRE through April 2019, and the methodology used to quantify the impacts analysis discussed in section V of this preamble. The EPA is also seeking comments on the accuracy of the control technology assessment and/or whether there are other compliance options available to meet the proposed revised emissions limits. Finally, we request comment on the Agency's approach for using a Benefit per-Ton value to quantify benefits as well as the utility of performing full-form modeling for the final rule.

The current version of this regulation contains language which details how facilities that seek to monitor CO_2 in lieu of oxygen as part of their CEMS used to demonstrate compliance with the CO emission limits in this subpart must have this approach approved as an alternative method before doing so. The EPA is seeking comment on replacing the requirement to have approval of an alternative test method with a required methodology to be followed when monitoring CO_2 in lieu of oxygen as the diluent for CO which would account for any changes in CO_2 emission levels caused by a control device, etc. Additionally, the EPA believes it is appropriate to expand this language to the monitoring of all pollutants when CO_2 is used as the diluent and seeks comment on this as well. Finally, in the course of reviewing the monitoring language under 40 CFR part 63, subpart DDDDD, the EPA is proposing to remove several requirements for the continuous monitoring of moisture and flow which were found to be unnecessary. We also seek comment on these revisions. A draft of the language we would propose to accomplish these revisions is included in the docket.

VII. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders*.

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is an economically significant regulatory action that was submitted to OMB for review. Any changes made in response to OMB recommendations have been documented in the docket. The RIA for the ICI Boilers NESHAP Reconsideration contains the estimated costs, benefits, and other impacts associated with this action, and it is available in the docket.

B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs

This action is expected to be an Executive Order 13771 regulatory action. Details on the estimated costs of this proposed rule can be found in the EPA's analysis of the potential costs and benefits associated with this action, which is the RIA for this proposal.

C. Paperwork Reduction Act (PRA)

The new information collection activities imposed by this proposed rule have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2028.10. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

The proposed amendments change several emission limits as part of the EPA's response to the remand granted on December 23, 2016, by the D.C. Circuit. The changes result in more stringent emission limits in some cases, which is expected to require additional recordkeeping and reporting burden. This increase is a result of additional monitoring and control devices anticipated to be installed to comply with the more stringent emission limits in the proposed amendments. With additional control devices, comes additional control device parametric monitoring, or in the case of CO, continuous emissions monitoring, and the associated records of that monitoring that must be maintained on-site and reported. Over the next 3 years, approximately 25 respondents operating existing large solid fuel-fired boilers and three respondents operating new solid fuel-fired boilers will be impacted by the new requirements under the standard as a result of these amendments. In addition to the costs to install and maintain records of additional monitoring equipment, the ICR details other additional record keeping and reporting burden changing records associated with adjusting operating parameter limit values, modifying monitoring plans, and familiarizing themselves with the changes in the proposed amendments.

Respondents/affected entities: Owners or operators of ICI boilers and process heaters.

Respondent's obligation to respond: Mandatory, 40 CFR part 63.

Estimated number of respondents: 28.

Frequency of response: Semi-annual, annual, periodic.

Total estimated burden: 1,080 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $307,000 (per year), includes $180,000 annualized capital or operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. The EPA will respond to any ICR-related comments in the final rule.

D. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. Of the 26 entities determined to be impacted by this action, only one is a small entity. This small entity is expected to not incur any costs associated with this action. More information on these small entity impacts is available in the RIA for this proposal.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. The action affects private industry and does not impose economic costs on State or local governments.

G. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

H. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of "covered regulatory action" in section 2-202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

I. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a "significant energy action" because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. The energy impacts estimated for this proposed rule increased only slightly the energy impacts estimated for the March 21, 2011, final rule which was concluded not to be a significant regulatory action under Executive Order 13211. Therefore, we conclude that this proposed rule, when implemented, is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

J. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

K. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations, and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994).

The documentation for this decision is contained in the preamble to the March 2011 final rule (see 76 FR 15662). For the March 2011 final rule, the EPA determined that the rule would not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. Compared to the final rule, the proposed amendments are somewhat more stringent for some subcategories and, thus, the overall increased health benefits demonstrate that the conclusion from the environmental justice analysis conducted for the final rule are still valid.

List of Subjects in 40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Reporting and recordkeeping requirements.

______________________________.
Dated:

____
Andrew Wheeler,

Administrator.

For the reasons stated in the preamble, 40 CFR part 63 is proposed to be amended as follows:

PART 63-NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

1. The authority citation for part 63 continuous to read as follows:

Authority: 42 U.S.C. 7401, *et seq*.

Subpart DDDDD – NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR MAJOR SOURCES: INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS AND PROCESS HEATERS

2. Section 63.7500 is amended by revising paragraph (a) introductory text and paragraphs (a)(1), (c), and (e) to read as follows:

§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b) through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 15 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under §63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate either steam, cogenerate steam with electricity, or both. The output-based emission limits, in units of pounds per

megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate only electricity. Boilers that perform multiple functions (cogeneration and electricity generation) or supply steam to common headers would calculate a total steam energy output using equation 21 of §63.7575 to demonstrate compliance with the output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, but on or after [**DATE 3 YEARS AFTER DATE OF PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]**, you must comply with the emission limits in Table 1 to this subpart. If you operate an existing boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(v), but on or after **[DATE 3 YEARS AFTER DATE OF PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER]** you must comply with the emission limits in Table 2 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010, and before May 20, 2011, you may comply with the emission limits in Table 11 or 14 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction on or after May 20, 2011, and before December 23, 2011, you may comply with the emission limits in Table 12 or 14 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction on or after December 23, 2011, and before April 1, 2013, you may comply with the emission limits in Table 13 or 14 to this subpart until January 31, 2016.

(iv) If you operate a new boiler or process heater, you may comply with the emission limits in Table 1 or 14 until you must comply with the emission limits in Table 1 to this subpart.

(v) If you operate an existing boiler or process heater, you may comply with the emission limits in Table 2 or 15 until you must comply with the emission limits in Table 2 to this subpart.

* * * * *

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 15 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

* * * * *

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 15 to this subpart, or the operating limits in Table 4 to this subpart.

* * * * *

3. Section 63.7505 is amended by revising paragraph (c) to read as follows:

§ 63.7505 What are my general requirements for complying with this subpart?

* * * * *

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard. Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance stack testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 15 to this subpart.

* * * * *

4. Section 63.7510 is amended by revising paragraph (a) introductory text and paragraphs (b), (c), (f), and (j) to read as follows:

§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 15 of this subpart through performance (stack) testing, your initial compliance requirements include all the following:

* * * * *

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 15 to this subpart for HCl, mercury, or

TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart. The fuels described in paragraph (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to § 63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 15 to this subpart, as specified in § 63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

* * * * *

(f) For new or reconstructed affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013, or within 180 days after startup of the source, whichever is later.

(i) If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 14 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 14 no later than July 29, 2016.

(ii) If you are demonstrating compliance with an emission limit in Table 14 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than **[date 3 years after date of publication of final rule in the Federal Register]**.

*   *   *   *   *

(j) For existing affected sources (as defined in § 63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Tables 2 or 14, to this subpart, as applicable, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in § 63.7495.

*   *   *   *   *

5. Section 63.7515 is amended by revising paragraphs (b), (c), (e), (g), and (i) to read as follows:

§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

*   *   *   *   *

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 15 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 15 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 15 to this subpart).

* * * * *

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 15 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level. If sampling is conducted on 1 day per month, samples should be no less than 14 days apart, but if multiple samples are taken per month, the 14-day restriction does not apply.

* * * * *

(g) For affected sources (as defined in § 63.7490) that have not operated since the previous compliance demonstration and more than 1 year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 15 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) and the schedule described in § 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

* * * * *

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in § 63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 15 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in § 63.7510(a).

6. Section 63.7520 is amended by revising paragraph (d) to read as follows:

§ 63.7520 What stack tests and procedures must I use?

* * * * *

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 15 to this subpart.

* * * * *

7. Section 63.7521 is amended by revising paragraphs (a) and (c)(1)(ii) to read as follows:

§ 63.7521 What fuel analyses, fuel specification, and procedures must I use?

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard. For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 15 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section.

* * * * *

(c) * * *

(1) * * *

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during the testing period for sampling during performance stack testing.

* * * * *

8. Section 63.7522 is amended by revising paragraph (b) introductory text and paragraphs (d), (e)(1), (e)(2), (h), and (j)(1) to read as follows:

§ 63.7522 Can I use emissions averaging to comply with this subpart?

* * * * *

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 or 15 to this subpart as specified in paragraph (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

* * * * *

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 or 15 to this subpart at all times the affected units are subject to numeric emission limits following the compliance date specified in § 63.7495.

(e) * * *

(1) You must use Equation 1a or 1b or 1c of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 or 15 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis, use Equation 1b if you are complying with the emission limits on a steam generation (output) basis, and use Equation 1c if you are complying with the emission limits on a electric generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Hm\right) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq. 1a)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.
Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).
Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.
n = Number of units participating in the emissions averaging option.
1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times So\right) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 1b)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.
Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing

according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

So = Maximum steam output capacity of unit, i, in units of million Btu per hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}\left(Er \times Eo\right) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq.1c)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

Eo = Maximum electric generating output capacity of unit, i, in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to using Equation 1a of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 or 15 to this subpart that are in pounds per million Btu of heat input.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n}\left(Er \times Sm \times Cfi\right) \div \sum_{i=1}^{n}\left(Sm \times Cfi\right) \qquad \text{(Eq. 2)}$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).
Sm = Maximum steam generation capacity by unit, i, in units of pounds per hour.
Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.

1.1 = Required discount factor.

* * * * *

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 or 15 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

* * * * *

(j) * * *

(1) Conduct performance tests according to procedures specified in § 63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.

$$En = \sum_{i=1}^{n}(ELi \times Hi) \div \sum_{i=1}^{n} Hi \qquad \text{(Eq. 6)}$$

Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu) or parts per million (ppm).
ELi = Appropriate emission limit from Table 2 or 15 to this subpart for unit i, in units of lb/MMBtu or ppm.
Hi = Heat input from unit i, MMBtu.

* * * * *

9. Section 63.7525 is amended by revising paragraphs (a), (a)(2), (a)(2)(iv), (l), and (m) introductory text to read as follows:

§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 15 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in § 63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen (or carbon dioxide (CO_2)) according to the procedures in paragraphs (a)(1) through (6) of this section.

* * * * *

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 15 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B; part 75 of this chapter (if an CO_2 analyzer is used); the site-specific monitoring plan developed according to § 63.7505(d); and the requirements in § 63.7540(a)(8) and paragraph (a) of this section. Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 15 to this subpart.

* * * * *

(iv) Any CO CEMS that does not comply with § 63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 15 to this subpart.

*   *   *   *   *

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 15 of this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date a final performance specification for a HCl CEMS is published in the **Federal Register** or the date of approval of a site-specific monitoring plan.

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 15 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you elect to use an SO_2 CEMS to demonstrate continuous compliance with the HCl emission limit, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to either part 60 or part 75 of this chapter.

*   *   *   *   *

10. Section 63.7530 is amended by revising paragraphs (b)(4)(ii)(E) and (b)(4)(iii) and the introductory text of paragraph (h) to read as follows:

§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

*   *   *   *   *

(b) *   *   *

(4) *   *   *

(ii) *   *   *

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Tables 1, 2, or 11 through 15 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers (“back half”) of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the “back half” for other purposes.

* * * * *

(iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in § 63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

* * * * *

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 15 to this subpart, you must meet the work practice standard according to Table 3 of this subpart.

During startup and shutdown, you must only follow the work practice standards according to items 5 and 6 of Table 3 of this subpart.

* * * * *

11. Section 63.7533 is amended by revising paragraphs (a), (e), and (f) to read as follows:

§ 63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 or 15 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to § 63.7522(e) and for demonstrating monthly compliance according to § 63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at: *http://www.epa.gov/ttn/atw/boiler/boilerpg.html*.

* * * * *

(e) The emissions rate as calculated using Equation 20 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 or 15 to this subpart at all times the affected unit is subject to numeric emission limits, following the compliance date specified in § 63.7495.

(f) You must use Equation 20 of this section to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 or 15 to this subpart.

$$E_{adj} = E_m \times (1 - ECredits) \quad \text{(Eq. 20)}$$

Where:

E_{adj} = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.
E_m = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.
ECredits = Efficiency credits from Equation 19 for the affected boiler.

* * * * *

12. Section 63.7540 is amended by:

a. Revising paragraphs (a), (a)(8), and (a)(19) introductory text; and

b. Revising paragraphs (a)(8)(ii), (a)(9), and (b),

Revisions to read as follows:

§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 15 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

* * * * *

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 15 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

*   *   *   *   *

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 15 to this subpart at all times the affected unit is subject to numeric emission limits.

*   *   *   *   *

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify (PM CEMS only), operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in § 63.7505(d).

*   *   *   *   *

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 15 of this subpart.

*   *   *   *   *

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 15 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in § 63.7550.

*   *   *   *   *

13. Section 63.7545 is amended by revising paragraph (e)(3) to read as follows:

§ 63.7545 What notifications must I submit and when?

* * * * *

(e) * * *

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 15 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

* * * * *

14. Section 63.7555 is amended by revising paragraph (d) introductory text and paragraph (d)(5) to read as follows:

§ 63.7555 What records must I keep?

* * * * *

(d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 15 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

* * * * *

(5) If, consistent with § 63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 15 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

*   *   *   *   *

15. Section 63.7575 is amended by:

a. Adding, in alphabetical order, a definition for “12-month rolling average”;

b. Revising the definition of “Other gas 1 fuel”; and

c. Revising paragraphs (3) and (4) under the definition of “Steam output.”

The additions and revisions read as follows:

§ 63.7575 What definitions apply to this subpart?

*   *   *   *   *

12-month rolling average means the arithmetic mean of the previous 12 months of valid fuel analysis data. The 12 months should be consecutive, but not necessarily continuous if operations were intermittent.

*   *   *   *   *

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum mercury concentration of 40 micrograms/cubic meters of gas.

*   *   *   *   *

Steam output *   *   *

*   *   *   *   *

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be the appropriate emission limit from Table 1 or 2 or 14 or 15 of this subpart in units of pounds per million Btu heat input (lb per MWh).

(4) For a boiler that performs multiple functions and produces steam to be used for any combination of paragraphs (1), (2) and (3) of this definition that includes electricity generation of paragraph (3) of this definition, the total energy output, in terms of MMBtu of steam output, is

the sum of the energy content of steam sent directly to the process and/or used for heating (S_1), the energy content of turbine steam sent to process plus energy in electricity according to paragraph (2) of this definition (S_2), and the energy content of electricity generated by a electricity only turbine as paragraph (3) of this definition (MW_3) and would be calculated using Equation 21 of this section. In the case of boilers supplying steam to one or more common headers, S_1, S_2, and $MW_{(3)}$ for each boiler would be calculated based on the its (steam energy) contribution (fraction of total steam energy) to the common header.

$$SO_M = S_1 + S_2 + (MW_{(3)}\ x\ CFn) \qquad \text{(Eq. 21)}$$

Where:

SO_M = Total steam output for multi-function boiler, MMBtu
S_1 = Energy content of steam sent directly to the process and/or used for heating, MMBtu
S_2 = Energy content of turbine steam sent to the process plus energy in electricity according to (2) above, MMBtu
$MW_{(3)}$ = Electricity generated according to paragraph (3) of this definition, MWh
CFn = Conversion factor for the appropriate subcategory for converting electricity generated according to paragraph (3) of this definition to equivalent steam energy, MMBtu/MWh
CFn for emission limits for boilers in the unit designed to burn solid fuel subcategory = 10.8
CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal = 11.7
CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass = 12.1
CFn for emission limits for boilers in one of the subcategories of units designed to burn liquid fuel = 11.2
CFn for emission limits for boilers in the unit designed to burn gas 2 (other) subcategory = 6.2

* * * * *

16. Table 1 to subpart DDDDD is amended to read as follows:

Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters

As stated in § 63.7500, you must comply with the following applicable emission limits:
[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	3.0E-04 lb per MMBtu of heat input	4.1E-04 lb per MMBtu of steam output or 3.9E-03 lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E-07 [a]lb per MMBtu of heat input	8.7E-07 [a]lb per MMBtu of steam output or 1.1E-05 [a]lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
2. Units designed to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	1.1E-03 lb per MMBtu of steam output or 1.4E-02 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 2.9E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.

4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 30-day rolling average)	1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; three-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	590 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 30-day rolling average)	6.1E-01 lb per MMBtu of steam output or 6.5 lb per MWh; three-run average	1 hr minimum sampling time.

	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	1.4E-02 lb per MMBtu of steam output or 1.9E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3-percent oxygen	4.3E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (5.0E-03 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (5.2E-03 lb per MMBtu of steam output or 7.0E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 30-day rolling average)	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.1E-03 lb per MMBtu of heat input; or (8.4E-06 [a]lb per MMBtu of heat input)	5.0E-03 lb per MMBtu of steam output or 5.8E-02 lb per MWh; or (1.1E-05 [a]lb per MMBtu of steam output or 1.2E-04 [a]lb per MWh)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn	a. CO (or CEMS)	220 ppm by volume on a dry basis corrected to 3-	0.18 lb per MMBtu of steam output or 2.5 lb	1 hr minimum sampling time.

biomass/bio-based solids		percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 10-day rolling average)	per MWh; three-run average	
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (8.0E-03 lb per MMBtu of heat input)	3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (8.1E-03 lb per MMBtu of steam output or 1.2E-01 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 10-day rolling average)	3.5E-01 lb per MMBtu of steam output or 3.6 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.5E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	3.4E-03 lb per MMBtu of steam output or 3.5E-02 lb per MWh; or (5.2E-05 lb per MMBtu of steam output or 5.5E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3-percent oxygen	1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-02 lb per MMBtu of heat input; or (2.9E-	2.0E-02 lb per MMBtu of steam output or 1.6E-01 lb per MWh; or	Collect a minimum of 2 dscm per run.

		05 [a]lb per MMBtu of heat input)	(5.1E-05 lb per MMBtu of steam output or 4.1E-04 lb per MWh)	
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	180 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (900 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 30-day rolling average)	0.22 lb per MMBtu of steam output or 2.0 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	3.3E-02 lb per MMBtu of steam output or 3.7E-01 lb per MWh; or (5.5E-04 lb per MMBtu of steam output or 6.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	7.0E-05 lb per MMBtu of heat input	7.7E-05 lb per MMBtu of steam output or 9.7E-04 lb per MWh	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E-07 [a]lb per MMBtu of heat input	5.3E-07 [a]lb per MMBtu of steam output or 6.7E-06 [a]lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.

	b. Filterable PM (or TSM)	1.9E-03 lb per MMBtu of heat input; or (6.1E-06 lb per MMBtu of heat input)	2.1E-03 lb per MMBtu of steam output or 2.7E-02 lb per MWh; or (6.7E-6 lb per MMBtu of steam output or 8.5E-5 lb per MWh)	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 [a]lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1.2E-03 [a]lb per MMBtu of steam output or 1.6E-02 [a]lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a

			output or 1.8E-02 lb per MWh	minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	7.3E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	1.3E-02 lb per MMBtu of steam output or 7.6E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[c] If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before April 1, 2013, you may comply with the emission limits in Tables 11, 12 or 13 to this subpart until January 31, 2016. On and after January 31, 2016, but before [date 3 years after date of publication of final rule in the **Federal Register**] you may comply with the emission limits in Table 14 to this subpart. On and after [date 3 years after date of publication of final rule in the **Federal Register**], you must comply with the emission limits in Table 1 to this subpart.

[d] An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using CO_2 as a diluent correction in place of oxygen at 3 percent. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit and must also take into account that the 3-percent oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

17. Table 2 to subpart DDDDD is amended to read as follows:

Table 2 to Subpart DDDDD of Part 63—Emission Limits for Existing Boilers and Process Heaters

As stated in § 63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	**For the following pollutants . . .**	**The emissions must not exceed the following emission limits, except during startup and shutdown . . .**	**The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .**	**Using this specified sampling volume or test run duration . . .**
1. Units in all subcategories designed to burn solid fuel	a. HCl	2.0E-02 lb per MMBtu of heat input	2.3E-02 lb per MMBtu of steam output or 0.26 lb per MWh	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	5.4E-06 lb per MMBtu of heat input	6.2E-06 lb per MMBtu of steam output or 6.9E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	3.9E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input)	4.1E-02 lb per MMBtu of steam output or 4.8E-01 lb per MWh; or (5.6E-05 lb per MMBtu of steam output or 6.5E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average;	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.

		or (320 ppm by volume on a dry basis corrected to 3-percent oxygen[c], 30-day rolling average)		
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	150 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (340 ppm by volume on a dry basis corrected to 3-percent oxygen[c], 30-day rolling average)	0.14 lb per MMBtu of steam output or 1.6 lb per MWh; three-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (230 ppm by volume on a dry basis corrected to 3-percent oxygen[c], 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (150 ppm by volume on a dry basis corrected to 3-percent oxygen[c], 30-day rolling average)	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; three-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (720 ppm by volume on a dry	1.1 lb per MMBtu of steam output or 13 lb per MWh; three-run average	1 hr minimum sampling time.

		basis corrected to 3-percent oxygen[c], 30-day rolling average)		
	b. Filterable PM (or TSM)	3.4E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	4.0E-02 lb per MMBtu of steam output or 4.8E-01 lb per MWh; or (2.4E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3-percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (5.0E-03 lb per MMBtu of heat input)	3.7E-01 lb per MMBtu of steam output or 4.5 lb per MWh; or (5.9E-03 lb per MMBtu of steam output or 7.0E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solid	a. CO (or CEMS)	210 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (310 ppm by volume on a dry basis corrected to 3-percent oxygen[c], 30-day rolling average)	2.1E-01 lb per MMBtu of steam output or 2.3 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.1E-02 lb per MMBtu of heat input; or (6.4E-05 lb per MMBtu of heat input)	2.6E-02 lb per MMBtu of steam output or 0.30 lb per MWh; or (8.0E-05 lb per MMBtu of steam output or 9.0E-04 lb per MWh)	Collect a minimum of 1 dscm per run.

10. Suspension burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen[c], 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.1E-02 lb per MMBtu of heat input; or (8.0E-03 lb per MMBtu of heat input)	4.2E-02 lb per MMBtu of steam output or 5.8E-01 lb per MWh; or (8.1E-03 lb per MMBtu of steam output or 0.12 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (520 ppm by volume on a dry basis corrected to 3-percent oxygen[c], 10-day rolling average)	8.4E-01 lb per MMBtu of steam output or 8.4 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input)	2.5E-01 lb per MMBtu of steam output or 2.6 lb per MWh; or (2.8E-03 lb per MMBtu of steam output or 2.8E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid	a. CO	1,100 ppm by volume on a dry basis corrected to 3-percent oxygen	2.4 lb per MMBtu of steam output or 12 lb per MWh	1 hr minimum sampling time.
	b. Filterable	2.0E-02 lb per MMBtu of heat	5.5E-02 lb per MMBtu of steam	Collect a minimum of 2 dscm per run.

	PM (or TSM)	input; or (5.8E-03 lb per MMBtu of heat input)	output or 2.8E-01 lb per MWh; or (1.6E-02 lb per MMBtu of steam output or 8.1E-02 lb per MWh)	
13. Hybrid suspension grate units designed to burn biomass/bio-based solid	a. CO (or CEMS)	3,500 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (900 ppm by volume on a dry basis corrected to 3-percent oxygen[c], 30-day rolling average)	3.5 lb per MMBtu of steam output or 39 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input)	5.5E-01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E-04 lb per MMBtu of steam output or 6.3E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	1.1E-03 lb per MMBtu of heat input	1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	7.3E-07 [a]lb per MMBtu of heat input	8.8E-07 [a]lb per MMBtu of steam output or 1.1E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 [b]collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.

	b. Filterable PM (or TSM)	5.9E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	7.2E-02 lb per MMBtu of steam output or 8.2E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E-03 [a]lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03 [a]lb per MMBtu of steam output or 1.1E-01 [a]lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.2E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.7E-01 lb per MMBtu of steam output or 3.1 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam	For M26A, collect a minimum of 2 dscm per run; for M26, collect a

			output or 1.8E-02 lb per MWh	minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 2 dscm.
	d. Filterable PM (or TSM)	7.3E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input)	1.3E-02 lb per MMBtu of steam output or 7.6E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[c] An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using CO_2 as a diluent correction in place of oxygen at 3 percent. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit and must also take into account that the 3-percent oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[d] Before [date 3 years after date of publication of final rule in the **Federal Register**] you may comply with the emission limits in Table 15 to this subpart. On and after [date 3 years after date of publication of final rule in the **Federal Register**], you must comply with the emission limits in Table 2 to this subpart.

18. Table 3 of subpart DDDDD is amended by revising the entry for “5.” and “6.” to read as follows:

Table 3 to Subpart DDDDD of Part 63—Work Practice Standards

As stated in § 63.7500, you must comply with the following applicable work practice standards:

If your unit is . . .	You must meet the following . . .
* * * * * * *	
	a. You must operate all CMS during startup. b. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, liquefied petroleum gas, clean dry biomass, and any fuels meeting the appropriate HCl, mercury and TSM emission standards by fuel analysis.
	c. You have the option of complying using either of the following work practice standards. (1) If you choose to comply using definition (1) of "startup" in § 63.7575, once you start firing fuels that are not clean fuels you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose, OR (2) If you choose to comply using definition (2) of "startup" in § 63.7575, once you start to feed fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. You must engage and operate PM control within one hour of first feeding fuels that are not clean fuels[a]. You must start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a permit limit or a rule other than this subpart that require operation of the control devices. You must develop and implement a written startup and shutdown plan, as specified in § 63.7505(e).
	d. You must comply with all applicable emission limits at all times except during startup and shutdown periods at which time you must meet this work practice. You must collect monitoring

	data during periods of startup, as specified in § 63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.7555.
6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 15 to this subpart during shutdown	You must operate all CMS during shutdown. While firing fuels that are not clean fuels during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR but, in any case, when necessary to comply with other standards applicable to the source that require operation of the control device.
	If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, refinery gas, and liquefied petroleum gas.
	You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in § 63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in § 63.7555.

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19. Table 4 to subpart DDDDD is amended by revising the column headings to read as follows:

Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

As stated in § 63.7500, you must comply with the applicable operating limits:

When complying with a Table 1, 2, 11, 12, 13, 14, or 15 numerical emission limit using . . .	You must meet these operating limits . . .
* * * * * * *	

* * * * *

20. Table 7 to subpart DDDDD is amended by revising footnote “b” to read as follows:

Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits^{a,b}

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

* * * * * * *

[b] If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests. For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests. For maximum operating load, if you conduct multiple performance tests, you must set the maximum operating load at the lower of the maximum values established during the performance tests.

21. Table 8 to subpart DDDDD is amended by revising the entry for “8.” to read as follows:

Table 8 to Subpart DDDDD of Part 63—Demonstrating Continuous Compliance

As stated in § 63.7540, you must show continuous compliance with the emission limitations for each boiler or process heater according to the following:

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
* * * * * * *	
8. Emission limits using fuel analysis	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and
	b. Reduce the data to 12-month rolling averages; and
	c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 15 to this subpart.
	d. Calculate the HCI, mercury, and/or TSM emission rate from the boiler or process heater in units of lb/MMBtu using Equations 7, 8, and/or 9 in § 63.7530.
* * * * * * *	

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22. Add Table 14 to subpart DDDDD of part 63 to read as follows:

Table 14 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters

As stated in § 63.7500, you may continue to comply with the following applicable emission limits until [date 3 years after date of publication of final rule in the **Federal Register]**:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.28 lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E-07 [a]lb per MMBtu of heat input	8.7E-07 [a]lb per MMBtu of steam output or 1.1E-05 [a]lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
2. Units designed to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)	1.1E-03 lb per MMBtu of steam output or 1.4E-02 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 2.9E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. Carbon monoxide (CO) (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average;	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.

		or (320 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 30-day rolling average)		
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (340 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (230 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 30-day rolling average)	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (150 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 30-day rolling average)	1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; three-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3-	5.8E-01 lb per MMBtu of steam output or 6.8 lb	1 hr minimum sampling time.

designed to burn wet biomass fuel		percent oxygen, three-run average; or (390 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 30-day rolling average)	per MWh; three-run average	
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3-percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (4.2E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (310 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 30-day rolling average)	2.2E-01 lb per MMBtu of steam output or 2.6 lb per MWh; three-run average	1 hr minimum sampling time.

	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05 [a]lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E-04 [a]lb per MMBtu of steam output or 1.2E-03 [a]lb per MWh)	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 10-day rolling average)	1.9 lb per MMBtu of steam output or 27 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (520 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 10-day rolling average)	3.5E-01 lb per MMBtu of steam output or 3.6 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb	4.3E-03 lb per MMBtu of steam output or 4.5E-02 lb per MWh; or	Collect a minimum of 3 dscm per run.

		per MMBtu of heat input)	(5.2E-05 lb per MMBtu of steam output or 5.5E-04 lb per MWh)	
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3-percent oxygen	1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 [a]lb per MMBtu of heat input)	3.0E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (5.1E-05 lb per MMBtu of steam output or 4.1E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (900 ppm by volume on a dry basis corrected to 3-percent oxygen[d], 30-day rolling average)	1.4 lb per MMBtu of steam output or 12 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)	3.3E-02 lb per MMBtu of steam output or 3.7E-01 lb per MWh; or (5.5E-04 lb per MMBtu of steam output or 6.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E-04 lb per MMBtu of heat input	4.8E-04 lb per MMBtu of steam output or 6.1E-03 lb per MWh	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.

	b. Mercury	4.8E-07 [a]lb per MMBtu of heat input	5.3E-07 [a]lb per MMBtu of steam output or 6.7E-06 [a]lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	1.5E-02 lb per MMBtu of steam output or 1.8E-01 lb per MWh; or (8.2E-05 lb per MMBtu of steam output or 1.1E-03 lb per MWh)	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03 [a]lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1.2E-03 [a]lb per MMBtu of steam output or 1.6E-02 [a]lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.

	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

23. Add Table 15 to subpart DDDDD of part 63 to read as follows:

Table 15 to Subpart DDDDD of Part 63—Alternative Emission Limits for Existing Boilers and Process Heaters

As stated in § 63.7500, you may continue to comply with following emission limits until [date 3 years after date of publication of final rule in the **Federal Register]:**

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.27 lb per MWh	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	5.7E-06 lb per MMBtu of heat input	6.4E-06 lb per MMBtu of steam output or 7.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel	a. Filterable PM (or TSM)	4.0E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input)	4.2E-02 lb per MMBtu of steam output or 4.9E-01 lb per MWh; or (5.6E-05 lb per MMBtu of steam output or 6.5E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (320 ppm by volume on a dry basis corrected to 3-	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.

		percent oxygen[c], 30-day rolling average)		
4. Stokers/others designed to burn coal/solid fossil fuel	a. CO (or CEMS)	160 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (340 ppm by volume on a dry basis corrected to 3-percent oxygen[c], 30-day rolling average)	0.14 lb per MMBtu of steam output or 1.7 lb per MWh; three-run average	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (230 ppm by volume on a dry basis corrected to 3-percent oxygen[c], 30-day rolling average)	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (150 ppm by volume on a dry basis corrected to 3-percent oxygen[c], 30-day rolling average)	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; three-run average	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (720 ppm by volume on a dry basis corrected to 3-percent oxygen[c], 30-day rolling average)	1.4 lb per MMBtu of steam output or 17 lb per MWh; three-run average	1 hr minimum sampling time.

	b. Filterable PM (or TSM)	3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)	4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam output or 3.4E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3-percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.7E-01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solid	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (310 ppm by volume on a dry basis corrected to 3-percent oxygen[c], 30-day rolling average)	4.6E-01 lb per MMBtu of steam output or 5.2 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-01 lb per MMBtu of heat input; or (1.2E-03 lb per MMBtu of heat input)	1.4E-01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E-03 lb per MMBtu of steam output or 1.7E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
10. Suspension burners designed to	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3-	1.9 lb per MMBtu of steam output or	1 hr minimum sampling time.

burn biomass/bio-based solid		percent oxygen, three-run average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen[c], 10-day rolling average)	27 lb per MWh; three-run average	
	b. Filterable PM (or TSM)	5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)	5.2E-02 lb per MMBtu of steam output or 7.1E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (520 ppm by volume on a dry basis corrected to 3-percent oxygen[c], 10-day rolling average)	8.4E-01 lb per MMBtu of steam output or 8.4 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input)	3.9E-01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E-03 lb per MMBtu of steam output or 2.8E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid	a. CO	1,100 ppm by volume on a dry basis corrected to 3-percent oxygen	2.4 lb per MMBtu of steam output or 12 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (5.8E-03 lb per MMBtu of heat input)	5.5E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (1.6E-02 lb per	Collect a minimum of 2 dscm per run.

			MMBtu of steam output or 8.1E-02 lb per MWh)	
13. Hybrid suspension grate units designed to burn biomass/bio-based solid	a. CO (or CEMS)	3,500 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average; or (900 ppm by volume on a dry basis corrected to 3-percent oxygen[c], 30-day rolling average)	3.5 lb per MMBtu of steam output or 39 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input)	5.5E-01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E-04 lb per MMBtu of steam output or 6.3E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	1.1E-03 lb per MMBtu of heat input	1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E-06 [a]lb per MMBtu of heat input	2.5E-06 [a]lb per MMBtu of steam output or 2.8E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 [b]collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, three-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable	6.2E-02 lb per MMBtu of heat	7.5E-02 lb per MMBtu of steam	Collect a minimum of 1 dscm per run.

	PM (or TSM)	input; or (2.0E-04 lb per MMBtu of heat input)	output or 8.6E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E-03 [a]lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03 [a]lb per MMBtu of steam output or 1.1E-01 [a]lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, three3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; three-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.7E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	3.3E-01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.

	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 2 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of three dscm per run.