ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2002–0058; FRL–9936–20–OAR]

RIN 2060–AS09

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; notice of final action on reconsideration.

SUMMARY: This action sets forth the Environmental Protection Agency's (EPA's) final decision on the issues for which it granted reconsideration on January 21, 2015, that pertain to certain aspects of the January 31, 2013, final amendments to the ''National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters'' (Boiler MACT). The EPA is retaining a minimum carbon monoxide (CO) limit of 130 parts per million (ppm) and the particulate matter (PM) continuous parameter monitoring system (CPMS) requirements, consistent with the January 2013 final rule. The EPA is making minor changes to the proposed definitions of startup and shutdown and work practices during these periods, based on public comments received. Among other things, this final action addresses a number of technical corrections and clarifications of the rule. These corrections will clarify and improve the implementation of the January 2013 final Boiler MACT, but do not have any effect on the environmental, energy, or economic impacts associated with the proposed action. This action also includes our final decision to deny the requests for reconsideration with respect to all issues raised in the petitions for reconsideration of the final Boiler MACT for which we did not grant reconsideration.

DATES: This rule is effective November 20, 2015.

ADDRESSES: Docket ID No. EPA–HQ–OAR–2002–0058 contains supporting information for this action on the Boiler MACT. All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA Docket Center, EPA/DC, EPA WJC West Building, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744 and the telephone number for the Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For further information, contact Mr. Jim Eddinger, Energy Strategies Group, Sector Policies and Programs Division (D243–01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5426; fax number: (919) 541–5450; email address: *eddinger.jim@epa.gov.*

SUPPLEMENTARY INFORMATION:

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

ACC American Chemistry Council
AF&PA American Forest and Paper Association
API American Petroleum Institute
CAA Clean Air Act
CEMS Continuous emissions monitoring systems
CFR Code of Federal Regulations
CIBO/ACC Council of Industrial Boiler Owners
CISWI Commercial and Industrial Solid Waste Incineration
CO Carbon monoxide
CO_2 Carbon dioxide
CPMS Continuous parameter monitoring systems
CRA Congressional Review Act
EGU Electric Utility Steam Generating Unit
EPA U.S. Environmental Protection Agency
ESP Electrostatic precipitator
FSI Florida Sugar Industry
HCl Hydrogen chloride
Hg Mercury
HSG Hybrid suspension/grate
ICI Industrial, Commercial, Institutional
ICR Information collection request
MACT Maximum achievable control technology
MATS Mercury Air Toxics Standards
mmBtu/hr Million British thermal units per hour
NAICS North American Industrial Classification System
NEDACAP Natural Environmental Development Association's Clean Air Project
NESHAP National emission standards for hazardous air pollutants
NHPC New Hope Power Company
NO_X Nitrogen oxides
NSPS New source performance standards
NTTAA National Technology Transfer and Advancement Act
O_2 Oxygen
OMB Office of Management and Budget
ORD EPA Office of Research and Development
PAH Polycyclic aromatic hydrocarbons
PCB Polychlorinated biphenyls
PM Particulate matter
POM Polycyclic organic matter
ppm Parts per million
SO_2 Sulfur dioxide
SSM Startup, shutdown, and malfunction
SSP Startup and shutdown plan
the Court United States Court of Appeals for the District of Columbia Circuit
TSM Total selected metals
TTN Technology Transfer Network
UARG Utility Air Regulatory Group
UMRA Unfunded Mandates Reform Act
U.S.C. United States Code
WWW World Wide Web

Organization of this Document. The following outline is provided to aid in locating information in this preamble.

I. General Information

A. Does this action apply to me?

Categories and entities potentially affected by this reconsideration action include those listed in Table 1 of this preamble:

TABLE 1—REGULATED ENTITIES

Category	North American Industrial Classification System (NAICS) code [a]	Examples of potentially regulated entities
Any industry using a boiler or process heater as defined in the final rule.	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.

[a] North American Industrial Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this final action. To determine whether your facility would be affected by this final action, you should examine the applicability criteria in 40 CFR 63.7490 of subpart DDDDD. If you have any questions regarding the applicability of this final action to a particular entity, contact the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. How do I obtain a copy of this document and other related information?

The docket number for this final action regarding the Major Source Boiler MACT (40 CFR part 63, subpart DDDDD) is Docket ID No. EPA–HQ–OAR–2002–0058.

World Wide Web. In addition to being available in the docket, an electronic copy of this final action is available on the Technology Transfer Network (TTN) Web site. Following signature, the EPA posted a copy of the final action at *http://www.epa.gov/ttn/atw/boiler/boilerpg.html*. The TTN provides information and technology exchange in various areas of air pollution control.

C. Judicial Review

Under Clean Air Act (CAA) section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in United States Court of Appeals for the District of Columbia Circuit (the Court) by January 19, 2016. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

II. Background Information

On March 21, 2011, the EPA established final emission standards for industrial, commercial, and institutional (ICI) boilers and process heaters at major sources to meet hazardous air pollutant (HAP) standards reflecting the application of maximum achievable control technology (MACT)—the Boiler MACT (76 FR 15608). On January 31, 2013, the EPA promulgated final amendments to the Boiler MACT (78 FR 7138). Following that action, the Administrator received 13 petitions for reconsideration that identified certain issues that petitioners claimed warranted further opportunity for public comment.

The EPA received petitions dated March 28, 2013, from New Hope Power Company (NHPC) and the Sugar Cane Growers Cooperative of Florida. The EPA received a petition dated March 29, 2013, from the Eastman Chemical Company (Eastman). The EPA received petitions dated April 1, 2013, from Earthjustice, on behalf of Sierra Club, Clean Air Council, Partnership for Policy Integrity, Louisiana Environmental Action Network, and Environmental Integrity Project (hereinafter referred to as Sierra Club); American Forest and Paper Association on behalf of American Wood Council, National Association of Manufacturers, Biomass Power Association, Corn Refiners Association, National Oilseed Processors Association, Rubber Manufacturers Association, Southeastern Lumber Manufacturers Association, and U.S. Chamber of Commerce (hereinafter referred to as AF&PA); the Florida Sugar Industry (FSI); Council of Industrial Boiler Owners, American Municipal Power, Inc., and American Chemistry Council (hereinafter referred to as CIBO/ACC); American Petroleum Institute (API); and the Utility Air Regulatory Group (UARG) which also submitted a supplemental petition on July 3, 2013. Finally, the EPA received a petition dated July 2, 2013, from the Natural Environmental Development Association's Clean Air Project (NEDACAP) and CIBO. The EPA received revised petitions from CIBO/ACC on July 1, 2014, and on July 11, 2014, from Eastman. Both of these were revised to withdraw one of the issues raised in their initial submittal.

In response to the petitions, the EPA reconsidered and requested comment on several provisions of the January 31, 2013, final amendments to the Boiler MACT. The EPA published the proposed notice of reconsideration in the **Federal Register** on January 21, 2015 (80 FR 3090).

III. Summary of Final Action and Significant Changes Since Proposal

In this notice, we are finalizing amendments associated with certain issues raised by petitioners in their petitions for reconsideration on the 2013 final amendments to the Boiler MACT. These provisions are: (1) Definitions of startup and shutdown periods and the work practices that apply during such periods; (2) CO limits based on a minimum CO level of 130 ppm; and (3) the use of PM CPMS, including the consequences of exceeding the operating parameter. Additionally, the EPA is finalizing the technical corrections and clarifications that were proposed to correct inadvertent errors in the final rule and to provide the intended accuracy, clarity, and consistency, as well as correcting various typographical errors identified in the rule as published in the Code of Federal Regulations (CFR).

Most of these changes are very similar to those described in the proposed notice of reconsideration on January 21, 2015 (80 FR 3090). However, the EPA has made some changes in this final rule after consideration of the public comments received on the proposed notice of reconsideration. The changes are to clarify applicability and implementation issues raised by the commenters. We address several significant comments in this preamble. For a complete summary of the comments received and our responses thereto, please refer to the memorandum ''Response to 2015 Reconsideration Comments for Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants'' located in the docket for this rulemaking.

A. Definition of Startup and Shutdown Periods and the Work Practices That Apply During Such Periods

1. Definitions

In the January 31, 2013, final amendments to the Boiler MACT, the EPA finalized revisions to the definition of startup and shutdown periods, which were based on the time during which fuel is fired in the affected unit for the purpose of supplying steam or heat for heating and/or producing electricity or for any other purpose. Petitioners asserted that the definitions were not sufficiently clear. In response to these petitions, we proposed an alternative definition of startup in the January 21, 2015, proposed notice of reconsideration (80 FR 3093). This alternative definition clarified pre-startup testing activities and also expanded to allow for startup after a shutdown event instead of solely the initial startup of the affected unit. The alternative definition of startup as well as the definition of shutdown also incorporated a new term ''useful thermal energy'' to replace the term ''steam and heat'' to address petitioners' concerns of an ambiguous end of the startup period.

In today's action, the EPA is adopting two alternative definitions of ''startup,'' consistent with the proposed rule. The first definition defines ''startup'' to mean the first-ever firing of fuel, or the firing of fuel after a shutdown event, in a boiler or process heater for the purpose of supplying useful thermal energy for heating and/or producing electricity or for any other purpose. Under this definition, startup ends when any of the useful thermal energy from the boiler or process heater is supplied for heating, producing electricity, or any other purpose. The EPA is also adopting an alternative definition of ''startup'' which defines the period as beginning with the first-ever firing of fuel, or the firing of fuel after a shutdown event, in a boiler or process heater for the purpose of supplying useful thermal energy for heating, cooling, or process purposes or for producing electricity, and ending four hours after the boiler or process heater supplies useful thermal energy for those purposes. Sources demonstrating compliance using the alternative definition will be required to meet enhanced recordkeeping provisions. These enhancements will document when useful thermal energy is provided, what fuels are used during startup, parametric monitoring data to verify relevant controls are engaged, and the time when PM controls are engaged.

In the January 31, 2013 final rule, the EPA defined ''shutdown'' to mean the cessation of operation of a boiler or process heater for any purpose, and said this period begins either when none of the steam from the boiler is supplied for heating and/or producing electricity or for any other purpose, or when no fuel is being fired in the boiler or process heater, whichever is earlier. The EPA received petitions for reconsideration of this definition, asking that the agency clarify the term. The EPA proposed a definition of ''shutdown'' in January 2015 which clarified that shutdown begins when the boiler or process heater no longer makes useful thermal energy (rather than referring to steam supplied by the boiler) for heating, cooling, or process purposes and/or generates electricity, or when no fuel is being fed to the boiler or process heater, whichever is earlier. In today's action, the EPA is adopting a definition of ''shutdown'' that is consistent with the proposal, with some minor clarifying revisions. ''Shutdown'' is defined to begin when the boiler or process heater no longer supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes and/or generation of electricity, or when no fuel is being fed to the boiler or process heater, whichever is earlier.

The EPA received several comments on the proposed edits to the definitions of ''useful thermal energy,'' ''startup,'' and ''shutdown.''

a. Useful Thermal Energy

Several comments supported the alternative definitions of startup and shutdown to include the concept of useful thermal energy, which recognizes that small amounts of steam or heat may be produced when starting up a unit, but the amounts would be insufficient to operate processing equipment and insufficient to safely initiate pollution controls.

One comment stated that an alternative work practice period between the start of fuel combustion until 4 hours after useful thermal energy is supplied is unlawful because the EPA may set work practice standards only for categories or subcategories of sources, not for periods of operation. The comment further noted that work practice standards are allowed only if pollution is not emitted through a conveyance or the application of measurement methodology to a particular class of sources is not practicable, and the EPA has not stated either of these to be the case. The comment also claimed that, because the EPA has changed and extended startup and shutdown periods, the EPA must determine that emissions measurement is impracticable during startup and shutdown as they are now defined, which the EPA has not done.

The EPA recognizes the unique characteristics of ICI boilers and has retained the alternative definition, which incorporates the term ''useful thermal energy'' in the final rule, with some slight adjustments, as discussed below. The EPA disagrees with the commenter that the reference to ''a particular class of sources'' in CAA section 112(h)(2) limits the EPA's authority to determine, for a category or subcategory of sources, that it is infeasible to prescribe or enforce an emission standard for those sources during certain identifiable time periods, such as startup and shutdown. Contrary to the commenter's assertion, the EPA did make a determination under CAA section 112(h) that it is not feasible to prescribe or enforce a numeric standard during periods of startup and shutdown, because the application of measurement methodology is impracticable due to technological and economic limitations.

Information provided on the amount of time required for startup and shutdown of boilers and process heaters indicates that the application of measurement methodology for these sources using the required procedures, which would require more than 12 continuous hours in startup or shutdown mode to satisfy all of the sample volume requirements in the rule, is impracticable. In addition, the test methods are required to be conducted under isokinetic conditions (*i.e.,* steady-state conditions in terms of exhaust gas temperature, moisture, flow rate), which is difficult to achieve during these periods where conditions are constantly changing. Moreover, accurate HAP data from those periods is unlikely to be available from either emissions testing (which is designed for periods of steady state operation) or monitoring instrumentation such as continuous emissions monitoring systems (CEMS) (which are designed for measurements occurring during periods other than during startup or shutdown when emissions flow are stable and consistent). Upon review of this information, the EPA determined that it is not feasible to require stack testing, in particular, to complete the multiple required test runs during periods of startup and shutdown due to physical limitations and the short duration of startup and shutdown periods. Based on these specific facts for the Boilers and Process Heater source category, the EPA developed a separate standard for these periods, and we are finalizing amendments to the work practice standards to meet this requirement. As detailed in the response to this commenter in the 2013 final amendments to the Boiler MACT (EPA–HQ–OAR–2002–0058–3511–A1), the EPA continues to maintain that testing is impracticable during periods of startup and shutdown, despite the revisions to the definitions for the two terms as finalized in this action. We set standards based on available information as contemplated by CAA section 112. Compliance with the numeric emission limits (*i.e.,* PM or total selected metals (TSM), hydrogen chloride (HCl), mercury (Hg), and CO) are demonstrated by conducting performance stack tests. The revised definitions of startup and shutdown better reflect when steady-state conditions are achieved, which are required to yield meaningful results from current testing protocols.

Several comments requested that the EPA add the term ''flow rate'' to the definition of useful thermal energy, consistent with the preamble to the proposed notice of reconsideration (80 FR 3093). The EPA recognizes the importance of flow rate as a parameter for determining when useful thermal energy is being supplied by a boiler or process heater and has added this term to the definition in the final rule.

Two comments argued that for the alternative definitions of startup and shutdown to be useful, the term ''useful thermal energy'' must incorporate a primary purpose component that assures that the 4-hour startup period is not triggered until useful energy is supplied to the most demanding end use of the boiler. Several comments agreed with the EPA that startup ''should not end until such time that all control devices have reached stable conditions'' (*see* 80 FR 3094, column 1), but noted that the time frame of 4 hours after a unit supplies useful thermal energy is not workable for some boilers due to site-specific factors and technology differences. One commenter agreed with the EPA that the variation of practices and capabilities among fossil-fuel fired boilers warrants longer periods when work practices apply in lieu of ICI MACT emission limits.

The EPA agrees that the definition of ''useful thermal energy'' could be further clarified; however, we disagree that basing the end of startup on a primary purpose approach which considers the most demanding end use is an appropriate approach. Often times, ICI boilers can serve more than one purpose. As long as the boiler is providing useful thermal energy to one of its intended purposes, the unit is supplying ''useful thermal energy.'' The final definition of ''useful thermal energy'' incorporates the term ''flow'' to more appropriately reflect when the energy is provided for any primary purpose of the unit. We believe that supplying energy at the minimum temperature, pressure, and flow to any energy use system is the primary purpose of any unit.

b. Startup

Several comments claimed that even with an alternative definition of startup to incorporate the term ''useful thermal energy,'' the first definition remains unworkable. The act of supplying heat, steam, or electricity does not represent the functional end of the startup period, and some processes are designed such that downstream equipment receives heat and/or steam when fuel is being burned during startup of the boilers and/or process heaters.

The EPA has adjusted the first definition of startup to replace ''steam'' with ''useful thermal energy''. Additionally, the term ''useful thermal energy'' was revised to incorporate a minimum flowrate to more appropriately reflect when the energy is provided for any primary purpose of the unit. Together, these changes alleviate the concerns of when the startup period functionally ends. Boilers and process heaters should be considered to be operating normally at all times steam or heat of the proper pressure, temperature and flow rate is being supplied to a common header system or energy user(s) for use as either process steam or for the cogeneration of electricity.

c. Shutdown

Several comments supported the EPA's proposed definition of shutdown, because the proposed revisions now adequately address the circumstances for some affected units where fuel remaining in the unit on a grate or elsewhere continues to combust although fuel has been cut off and useful thermal energy is no longer generated. Two comments suggested that the definition could be clarified to recognize that the shutdown period begins when no useful steam or electricity is generated, or when fuel is no longer being combusted in the boiler. After the shutdown period ends, some steam may still be generated temporarily, even though the steam is not useful thermal energy (*i.e.,* the steam does not meet the minimum operating temperature, pressure, and flow rate).

The EPA has adjusted the definition of shutdown to replace the phrase ''makes useful thermal energy'' to ''supplies useful thermal energy.'' The shutdown period begins when no useful steam or electricity is generated, or when fuel is no longer being combusted in the boiler. The term ''supplies'' is the preferred phrase in the definition of shutdown instead of ''makes'' to be consistent with the definition of startup, and is a more accurate term to use to describe the function of the boiler or process heater.

2. Work Practices

The EPA is adopting work practices that apply during the periods of startup and shutdown which reflect the emissions performance achieved by the best performing units. These work practices include use of clean fuels during startup and shutdown. In addition, under the alternate work practice, sources must engage all applicable control devices so that the emissions standards are met no later than four hours after the start of supplying useful thermal energy and must engage PM controls within one hour of first feeding non-clean fuels.

a. Clean Fuels

In the January 31, 2013, final amendments to the Boiler MACT, the EPA finalized a definition of ''clean fuels'' that could be used during periods of startup and shutdown to satisfy the clean fuels requirement. Petitioners claimed that the list of ''clean fuels'' was too narrow. In response to these petitions, the EPA proposed revisions to this term in the January 21, 2015, notice of reconsideration to include ''other gas 1'' fuels, as well as any fuels that meet the applicable TSM, HCl, and Hg emission limits based on fuel analysis. In today's action, the EPA is finalizing these proposed revisions to the definition of ''clean fuels'' and also adding ''clean dry biomass'' to the definition of ''clean fuels.''

The EPA received several comments on the proposed changes to the definition of clean fuels. Several comments supported the EPA's proposal to expand the list of eligible clean fuels for starting up a boiler or process heater to include all gaseous fuels meeting the ''other gas 1'' classification and any fuel that meets the applicable TSM, HCl, and Hg emission limits using fuel analysis. Another comment claimed that the EPA had not shown that boilers burning ''clean fuels'' or those fuels newly added to the ''clean fuels'' list (*i.e.,* other gas 1) can meet CO standards or that emissions of organic HAP will not increase. This comment suggested that allowing sources to emit more CO or organic HAP than is permitted by the standards, is not ''consistent with'' CAA section 112(d), and is, therefore, unlawful. This comment also expressed concerns that broadening the ''clean fuel'' definition would allow sources to burn tires as ''clean fuel,'' provided that they meet fuel analysis requirements for Hg, TSM, and HCl despite the fact that burning tires plainly increases polycyclic aromatic hydrocarbons (PAH).

Based on the comments received, the EPA is finalizing an expanded list of clean fuels to add any fuels that meet the applicable TSM, HCl and Hg emission limits based on fuel analysis. The EPA disagrees with the comment that the clean fuels requirement is inconsistent with CAA section 112(d) because it fails to address emissions of CO or organic HAP. These pollutants are byproducts of the combustion process, and, therefore, emissions are not fuel-dependent and cannot be measured through fuel analysis. For instance, the formation of POM is effectively reduced by good combustion practices (*i.e.,* proper air to fuel ratios). In addition, because these pollutants are byproducts of the combustion process, the EPA does not expect most units to require post-combustion controls to meet the CO limits once the startup period has ended, but instead will comply by conducting the required tune-up (which serves to reduce HAP emissions at all times, including during startup and shutdown), and adopting other combustion best practices. In contrast, the EPA expects many units to install one or more post-combustion controls to reduce emissions of HCl, Hg, or non-Hg metallic HAP. Because CO and organic HAP are combustion byproducts, emissions of CO and organic HAP are likely to vary little among boilers during startup since combustion practices during that period tend to be similar and well-controlled in order to prevent thermal stresses, and are not dependent on the fuel being combusted, unlike Hg, HCl, and other hazardous metals. Therefore, it is reasonable for EPA to conclude that emissions during startup will reflect the maximum degree of reduction of CO and organic HAP, as well as other HAP, achieved during startup. For these reasons, today's action retains the proposed requirements to qualify as a clean fuel through fuel analysis data.

Regarding the commenter's concerns with tires, specifically, the EPA has reviewed the fuel analysis data for tire derived fuel for HCl, Hg, and TSM emissions submitted in the databases used in the final rule. None of the samples indicate that tires could demonstrate compliance with the TSM limit for solid fossil fuels. Thus, the EPA believes that tires would not qualify as a ''clean fuel.''

Two commenters asked the EPA to include dry biomass (*i.e.,* moisture content less than 20 percent) in the list of clean fuels allowed during startup and shutdown. The commenters noted that the chemical makeup and combustion characteristics are similar to paper and cardboard which are currently included. Further, dry biomass has low chloride, Hg, and moisture content, burns cleaner than other solid fuels, and produces low HCl, Hg, and CO. The list of clean fuels was expanded to include ''clean dry biomass.'' The EPA has reviewed boiler information collection request (ICR) fuel analysis data and AP–42 emission factor data for wood combustion. The ICR fuel analysis data for solid fuels often exclude numeric values for certain metallic HAP that were reported as below detection levels. These data show that clean dry biomass can meet the Hg and HCl limits for solid fuels and the TSM levels in dry biomass are 6 times lower than in solid fossil fuels. Therefore, the EPA has finalized the list of clean fuels to include clean dry biomass. The EPA added the phrase ''clean dry biomass'' to Table 3 to subpart DDDDD of part 63, item 5.b. The EPA also defined this new term for this subpart drawing on similarly defined term in the ''Identification of Non-Hazardous Secondary Materials That Are Solid Waste'' rulemaking. Under the final rule, clean dry biomass fuels are now categorically accepted as clean fuels and do not need to demonstrate that the fuel meets the TSM, Hg, and HCl emission limits with each new fuel shipment.

Based on comments received to clarify how the ''clean fuel'' provision works, the EPA also made several corrections in the final rule. Text in 40 CFR 63.7555(d)(11) is added to acknowledge the possibility for additional clean fuels. Language in 40 CFR 63.7555(d)(11) was revised to replace the phrase ''coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases'' with ''fuels that are not clean fuel.''

For consistency, the phrase ''coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases'' was replaced with ''fuels that are not clean fuel'' in Table 3 to subpart DDDDD of part 63, items 5.c and 6.

b. Engaging Pollution Controls

The January 2013 final amendments to the Boiler MACT included a provision for boilers and process heaters when they start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases to engage applicable pollution control devices except for limestone injection in fluidized bed combustion (FBC) boilers, dry scrubbers, fabric filters, selective non-catalytic reduction, and selective catalytic reduction, which must start as expeditiously as possible. The EPA received several petitions for reconsideration of this aspect of the work practice standard expressing safety concerns with engaging electrostatic precipitator (ESP) control devices. These petitions urged the EPA to revise requirements to include ESP energization with the other controls that are to be started as expeditiously as possible rather than when solid fuel firing is first started.

In response to these petitions, the January 2015 proposal included an alternate requirement to engage all control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. Under the proposal, owners or operators would be required to engage PM control within 1 hour of first firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases. Owners or operators using this alternative would have to develop and implement a written startup and shutdown plan (SSP) and the SSP must be maintained on site and available upon request for public inspection. The EPA also proposed to allow a source to request a case-by-case extension to the 1-hour period for engaging the PM controls based on evidence of a documented manufacturer-identified safety issue and proof that the PM control device is adequately designed and sized to meet the filterable PM emission limit. The EPA is adopting the proposed requirements with minor revisions.

The EPA received several comments on the proposed revisions for engaging pollution controls. One comment supported the EPA's recognition that some HAP emission control technologies require specific operating conditions before being engaged and should be excluded from operation as soon as primary fuel firing begins. Several comments requested that the EPA add ESPs to the list of controls that must be started as expeditiously as possible, noting that the 1-hour requirement for engaging ESPs is unreasonable. Another comment considered the EPA's decision to set a less stringent work practice standard that allows boilers to operate without pollution controls to be inconsistent with CAA section 112(d)(2) and arbitrary. This commenter also considered the requirement to engage applicable pollution controls ''as expeditiously as possible'' within the startup period to be inconsistent with CAA section 112(d) and unlawful, as well as arbitrary and capricious. The commenter states that it is not acceptable for a standard to allow sources to do whatever is ''possible'' for them. The commenter stated that the point of a national standard is to set one limit that governs all the sources to which it applies.

The EPA has established a work practice for periods of startup and shutdown because it is infeasible to measure emissions during these periods. Moreover, accurate HAP data from those periods are unlikely to be available from either emissions testing (which is designed for periods of steady state operation) or monitoring instrumentation such as CEMS (which are designed for measurements occurring during periods other than during startup or shutdown when emissions flow is stable and consistent). The work practice for PM controls was established by evaluating the performance of the best performing sources as determined by the EPA. For the Mercury and Air Toxics Standards (MATS), the EPA conducted an analysis of nitrogen oxide (NO_X) and sulfur dioxide (SO_2) CEMS data from electric utility steam generating units (EGUs) to determine the best performing sources with respect to NO_X and SO_2 emissions (79 FR 68779 November 19, 2014). The best performing sources are those whose control devices are operational within 4 hours of starting electrical generation. Since the types of controls used on EGUs are similar to those used on industrial boilers and the start of electricity generation is similar to the start of supplying useful thermal energy, we believe that the controls on the best performing industrial boilers would also reach stable operation within four hours after the start of supplying useful thermal energy and have included this timeframe in the proposed alternate definition. This conclusion was supported by the limited information (13 units) the EPA did have on industrial boilers and by information (76 units) submitted by CIBO obtained from an informal survey of its members on the time needed to reach stable conditions during startup. The time reported, in the CIBO survey summary, to reach stable operation after coming online (supplying useful thermal energy) of the best performing units ranged from 1 to 4 hours. See the docketed memorandum ''2015 Assessment of Startup Period for Industrial Boilers.''

The EPA also maintains that the best performers are able to engage their PM control devices within 1 hour of coal, biomass, or residual oil combustion. In the January 2013 final Boiler MACT rule and in the January 2015 reconsideration proposal, the EPA stated that once an affected unit starts firing coal, biomass, or heavy liquid fuel, all of the applicable control devices had to be engaged (with certain listed exceptions). The listed exceptions did not include ESP for controls of PM emissions and, thus, the EPA's intent was that ESP controls would be engaged (*i.e.,* operational) at the moment non-clean fuel are fired. We did receive comments making us question the ability of most affected units to engage their ESP controls so quickly after first firing non-clean fuel. These comments suggested that there may need to be some flexibility. For this reason, we are providing a 1-hour period of time following the initiation of firing of non-clean fuels before PM controls must be engaged. Therefore, we are finalizing as part of the alternative work practice that PM control must be engaged within 1 hour of the time non-clean fuels are introduced into the affected unit. We have also added requirements to document that PM control is being achieved through the operation of the PM controls. The requirement to engage and operate the PM controls within 1 hour of non-clean fuels being charged to the units is intended to ensure that PM and HAP reductions will occur as quickly as possible after primary fuel combustion begins. We continue to believe that sources will be able to engage and operate their controls to comply with the standards at the end of startup, and that sources can make physical and/or operational changes at the facility to ensure compliance at the end of startup. As noted before, the EPA believes it appropriate to base its startup and shutdown work practices on those practices employed by the best performers. Because the above information indicates that ESPs can be energized within 1 hour of coal firing being started, we are finalizing that PM controls must be engaged within 1 hour of starting to fire non-clean fuels.

Several commenters were also concerned with compliance deadlines and asked the EPA to provide and finalize a more streamlined procedure for units needing more than 1 hour to safely initiate PM control during startup. They were concerned that their case-by-case extensions would not be approved by the local authority by the compliance deadlines, considering that the EPA must finalize this rule before it is adopted by the state.

The EPA is finalizing the provision allowing an owner or operator to apply for a boiler-specific case-by-case alternative timeframe with the requirement to engage PM control devices within 1 hour of firing non-clean fuels. However, the delegated authority will only consider such requests for boilers that can provide evidence of a documented manufacturer-identified safety issue, proof that the PM control device is adequately designed and sized to meet the final PM emission limit, and that it can demonstrate it is unable to safely engage and operate the PM controls. In its request for the case-by-case determination, the owner or operator must provide, among other materials, documentation that: (1) The boiler is using clean fuels to the maximum extent possible to bring the boiler and PM control device up to the temperature necessary to alleviate or prevent the safety issues prior to the combustion of non-clean fuels in the boiler, (2) the boiler has explicitly followed the manufacturer's procedures to alleviate or prevent the safety issue, (3) the source provides details of the manufacturer's statement of concern, and (4) the source provides evidence that the PM control device is adequately designed and sized to meet the final PM emission limit. In addition, the source will have to indicate the other measures it will implement to limit HAP emissions during periods of startup and shutdown to ensure a control level consistent with the final work practice requirements.

The EPA is finalizing a provision, 40 CFR 63.7555(d)(13), that provides that an owner or operator may apply for an alternative timeframe with the PM controls requirement to the permitting authority. We recognize that there may be very limited circumstances that compel an alternative approach for a specific unit. The EPA has added language to Table 3 to subpart DDDDD of part 63, item 5.c to clarify that a written SSP must be developed. Text was added to Table 3 to subpart DDDDD of part 63—footnote ''a'' to acknowledge that an alternative timeframe to the PM controls requirement can be granted by the EPA or the appropriate state, local, or tribal permitting authority that has been delegated authority.

B. Revised CO Limits Based on a Minimum CO Level of 130 ppm

In the January 2013 final amendments to the Boiler MACT, the EPA established a CO emission limit for certain subcategories at a level of 130 ppm, based on an analysis of CO levels and associated organic HAP emission reductions. The January 2015 proposal retained these emission limits, but requested additional data to support whether or not these limits were appropriate or should be modified. The EPA is retaining these limits, as discussed below.

The EPA received numerous comments supporting the minimum CO level of 130 ppm, adjusted to 3-percent oxygen (O_2). These comments agreed that the level selected was within the range of where the relationship between CO and organic HAP breaks down. Many of these comments also noted that the level was consistent with other EPA regulations for hazardous waste combustors and industrial furnace rules.

One comment disagreed that the minimum CO level of 130 ppm reflects the CO emissions achieved by the best performers in this subcategory, and contended that this level does not satisfy the requirements of CAA section 112(d)(3). This comment also disagreed with the use of formaldehyde as a surrogate for other organic HAPs and provided supporting evidence.[1] The commenter concluded that formaldehyde emissions are formed differently than polychlorinated biphenyls (PCBs) and PAHs, and they noted that combustion practices that reduce emissions of PCBs and PAHs (*i.e.* extremely high temperatures) can increase emissions of CO. The comments also noted that the gaseous properties of formaldehyde emissions differ from PCBs and PAH emissions, which are particles.

After consideration of the comments received, the EPA is maintaining a minimum level of 130 ppm CO at 3-percent O_2. The issue of whether or not CO is an appropriate surrogate for formaldehyde (a representative organic HAP in boiler emissions), or non-dioxin organic HAP in general, is outside the scope of this reconsideration, since the reconsideration solicited comment only on the CO limits established at 130 ppm, not on the broader issue of using CO as a surrogate for organic HAP. Moreover, the appropriateness of CO as a surrogate is currently part of ongoing litigation before the Court (*United States Sugar Corporation* v. *EPA, pending case No. 11–1108*). As noted in the final amendments to the Boiler MACT (78 FR 7145 January 31, 2013), the EPA selected formaldehyde ''. . . as the basis of the organic HAP comparison because it is the most prevalent organic HAP in the emission database and a large number of paired tests existed for boilers and process heaters for CO and formaldehyde.'' As for the additional evidence submitted with the comments, we do not disagree that the gaseous properties of formaldehyde emissions differ from PCBs and PAH emissions. However, the surrogacy testing conducted by the EPA's Office of Research and Development (ORD) clearly show a high correlation between CO and PAH, similar to the correlation between formaldehyde and CO. Furthermore, as shown in figure 2 of the technical report provided in Attachment A to the commenter letter, PAH emissions decrease with increasing O_2 levels, but then increase with higher levels of excess O_2, similar to the trend we saw in our assessment of the correlation between CO and formaldehyde.

C. PM CPMS

The March 2011 Boiler MACT final rule required units greater than 250 million British thermal units per hour (MMBtu/hr) combusting solid fossil fuel or heavy liquid to install, maintain, and operate PM CEMS to demonstrate compliance with the applicable PM emission limit (*see* 76 FR 15615, March 21, 2011). In response to petitions for reconsideration challenging PM CEMS, the EPA finalized a CPMS for demonstrating continuous compliance with the PM standards in the January 2013 final amendments to the Boiler MACT. The CPMS requirement allowed sources a number of exceedances of the operating limit before the exceedance would be presumed to be a violation, and also allowed certain low emitting sources to ''scale'' their site-specific operating limit to 75 percent of the emission standard. The EPA received petitions for reconsideration on the PM CPMS provisions and proposed these provisions again in January 2015 to provide additional opportunity for comment.

Several comments expressed concern about the cost and burden of the PM CPMS requirements. The combination of periodic compliance emissions testing and continuous monitoring of operational and parametric control measure conditions is appropriate for assuring continuous compliance with the emissions limitations. Without recurring testing, the EPA would have no way to know if parameter ranges established during initial performance testing remained viable in the future.

Several comments also contended that the CPMS limit should be based on the highest reading during the initial performance test instead of the average of the readings during each of the three test runs. The EPA disagrees with the commenters. Requiring PM CPMS to correspond to the average of three PM test runs rather than the single highest test run during the performance test alleviates the potential for setting an operating limit that corresponds to an emissions result higher than the emission standard, which could occur if the limit corresponded to the highest reading.[2] The EPA reiterates the statement in the January 2015 preamble that a 4th deviation of the PM CPMS operating limit in a 12-month period is a presumptive violation of the emissions standard. However, this is just a presumption which may be rebutted with evidence from the process controls, control monitoring parameters, repair logs, and associated Method 5 performance tests. In addition, the operating limit is based on a 30-day rolling average, which provides for additional cushion on variability of PM

[1] *See* Exhibit A from commenter, EPA–HQ–OAR–2002–0058–3919–A1.

[2] S. Johnson, memo to Docket ID No. EPA–HQ–OAR–2011–0817, ''Establishing an Operating Limit for PM CPMS,'' November 2012.

readings beyond just the initial performance test.

Based on comments, the EPA is maintaining the PM CPMS requirement as promulgated with minor adjustments as discussed below.

One commenter requested that the word ''certify'' be removed from 40 CFR 63.7525(b) and (b)(1). The EPA agrees that a PM CPMS is not a ''certified'' instrument, in that it is not certified through a performance specification. We have removed this language from the final rule.

IV. Technical Corrections and Clarifications

In the January 21, 2015, notice of reconsideration, the EPA also proposed to correct typographical errors and clarify provisions of the final rule that may have been unclear. This section of the preamble summarizes the significant changes made to the proposed corrections and clarifications, as well as corrections and clarifications being finalized based on comment.

A. Opacity Is an Operating Parameter

Commenters contended that the opacity operating limit of 10-percent may be an appropriate indicator of compliance with the applicable Boiler MACT PM limits for some boilers, but it is not an appropriate indicator of compliance for all boilers in all solid fuel subcategories.

Commenters also contend that the 10-percent opacity level is an ''operating limit,'' not an emission limit, and is utilized as an indicator of compliance with the Boiler MACT PM limit. Operating limit requirements are provided in Table 4 to subpart DDDDD of part 63, and include opacity. Emission limits are included in Tables 1 and 2 to subpart DDDDD of part 63 and do not include opacity. Commenters added that the language in 40 CFR 63.7500(a)(2) creates a conflict. By requiring a facility to request an alternate opacity parameter limit via 40 CFR 63.6(h)(9), the commenters claim that the EPA will be subjecting units to a more stringent PM standard than the established MACT floor because this process will not be feasible to complete prior to the compliance date. To resolve this issue, commenters asked that the EPA delete 40 CFR 63.7570(b)(2) so it will be clear that a request for an alternate opacity operating parameter limit is accomplished under 40 CFR 63.8(f) per 40 CFR 63.7570(b)(4) and 40 CFR 63.7500(a)(2).

The EPA agrees that the variation in PM limits for various solid fuel subcategories warrants some flexibility and similar variation in opacity limits. Opacity serves as a surrogate indicator of PM emissions, but was not intended by the EPA as an emission limit under the rule. Rather, it was intended to be an operating limit, which is established on a source-specific basis. Therefore we are revising the opacity operating limit such that affected facilities will have the option to comply with the 10-percent operating limit or a site-specific value established during the performance test based on the highest hourly average, which is consistent with how the other operating limits are established.

To implement this change in the final rule, 40 CFR 63.7570(b) is revised to remove the text currently in paragraph (b)(2), and the phrase ''or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation'' is added to Table 4 to subpart DDDDD of part 63, item 3; Table 4 to subpart DDDDD of part 63, item 6; and Table 8 to subpart DDDDD of part 63, item 1.c. Table 7 to subpart DDDDD of part 63 is expanded to include the process for establishing operating limits and item c is added.

B. CO Monitoring and Moisture Corrections

Commenters asked that since the applicable CO emission limits of the rule are expressed on a ''dry'' basis, the EPA should include additional provisions in the final rule to allow carbon dioxide (CO_2) CEMS to be used without petitioning for alternative monitoring procedures. Commenters also observed that 40 CFR 63.7525(a)(2) cross-references other requirements, including 40 CFR part 75, which do not address CO monitoring and do not fully address the moisture correction.

Language is added to 40 CFR 63.7525(a)(2)(vi) to clarify requirements when CO_2 is used to correct CO emissions and CO_2 is measured on a wet basis.

It is also acknowledged that CO concentration on a dry basis corrected to 3-percent O_2 can be calculated using data from the CO_2 CEMS and equations contained in EPA Method 19 instead of during the initial compliance test. Language is added to Table 1 to subpart DDDDD of part 63, as well as footnote ''d'' and footnote ''c'' in the following tables: Table 2, Table 12, and Table 13 to subpart DDDDD of part 63.

C. Affirmative Defense for Violation of Emission Standards During Malfunction

The EPA received numerous comments on its proposal to remove from the current rule the affirmative defense to civil penalties for violations caused by malfunctions. Several commenters supported the removal of the affirmative defense for malfunctions. Other commenters opposed the removal of the affirmative defense provision.

First, commenters (AF&PA and Georgia-Pacific) urged the EPA to publish a new or supplemental statement of basis and purpose for the proposed rule that explains (and allows for public comment on) the appropriateness of applying the boiler/process heater emission standards to malfunction periods without an affirmative defense provision.

Second, a commenter (AF&PA) argued the affirmative defense was something that the EPA considered necessary when the current standards were promulgated; it was part of the statement of basis and purpose for the standards required to publish under CAA section 307(d)(6)(A).

Third, commenters (CIBO/ACC) argued that the EPA should not remove the affirmative defense until the issue is resolved by the Court. Furthermore commenters argued the *NRDC* Court decision that the EPA cites as the reason for eliminating the affirmative defense provisions does not compel the EPA's proposed action here to remove the affirmative defense in this rule.

Fourth, several commenters argued that without affirmative defense, or adjusted standards, the final rule provides sources no means of demonstrating compliance during malfunctions.

Fifth, commenters (AF&PA, Class of '85 Regulatory Response Group, CIBO/ACC, American Electric Power, NHPC) urged the EPA to establish work practice standards that would apply during periods of malfunction instead of the emission rate limits or a combination of work practices and alternative numerical emission limitation. The EPA can address malfunctions using the authority Congress gave it in CAA sections 112(h) and 302(k) to substitute a design, equipment, work practice, or operational standard for a numerical emission limitation.

The Court recently vacated an affirmative defense in one of the EPA's CAA section 112(d) regulations. *NRDC* v. *EPA,* No. 10–1371 (D.C. Cir. April 18, 2014) 2014 U.S. App. LEXIS 7281 (vacating affirmative defense provisions in the CAA section 112(d) rule establishing emission standards for Portland cement kilns). The Court found that the EPA lacked authority to establish an affirmative defense for private civil suits and held that under the CAA, the authority to determine civil penalty amounts in such cases lies exclusively with the courts, not the

EPA. Specifically, the Court found: ''As the language of the statute makes clear, the courts determine, on a case-by-case basis, whether civil penalties are 'appropriate.' *see NRDC,* 2014 U.S. App. LEXIS 7281 at *21 (''[U]nder this statute, deciding whether penalties are 'appropriate' in a given private civil suit is a job for the courts, not EPA.''). As a result, the EPA is not including a regulatory affirmative defense provision in the final rule. The EPA notes that removal of the affirmative defense does not in any way alter a source's compliance obligations under the rule, nor does it mean that such a defense is never available.

Second, the EPA notes that the issue of establishing a work practice standard for periods of malfunctions or developing standards consistent with performance of best performing sources under all conditions, including malfunctions, was raised previously; see the discussion in the March 21, 2011 preamble to the final rule (76 FR 15613). In the most recent notice of proposed reconsideration (80 FR 3090, January 21, 2015), the EPA proposed to remove the affirmative defense provision, in light of the *NRDC* decision. The EPA did not propose or solicit comment on any revisions to the requirement that emissions standards be met at all times, or on alternative standards during periods of malfunctions. Therefore, the question of whether the EPA can and should establish different standards during malfunction periods, including work practice standards, is outside the scope of this final reconsideration action. The EPA further notes that this issue is currently before the Court in the pending case *United States Sugar Corporation* v. *EPA, pending case No. 11–1108.*

Finally, in the event that a source fails to comply with an applicable CAA section 112(d) standard as a result of a malfunction event, the EPA's ability to exercise its case-by-case enforcement discretion to determine an appropriate response provides sufficient flexibility in such circumstances as was explained in the preamble to the proposed rule. Further, as the Court recognized, in an EPA or citizen enforcement action, the Court has the discretion to consider any defense raised and determine whether penalties are appropriate. Cf. *NRDC,* 2014 U.S. App. LEXIS 7281 at *24 (arguments that violation were caused by unavoidable technology failure can be made to the courts in future civil cases when the issue arises). The same is true for the presiding officer in EPA administrative enforcement actions.

D. Definition of Coal

The last part of the definition of coal published in the final amendments to the Boiler MACT on January 31, 2013 (78 FR 7186), reads as follows: ''Coal derived gases are excluded from this definition [of coal].'' In the January 2015 proposal (80 FR 3090), the EPA proposed to modify this definition to read as follows: ''Coal derived gases and liquids are excluded from this definition [of coal].'' The EPA characterized its proposed change to the definition as one of several ''clarifying changes and corrections.'' This proposed change was based on a question received on whether coal-derived liquids were meant to be included in the coal definition.

The EPA received several comments disagreeing with the proposed change to the definition of coal, and indicating such a change would have a substantive effect on some affected facilities. One commenter who operates a facility with coal-derived liquids contended that the composition and emission profile of these liquids more closely resemble the coal from which they are derived than any of light or heavy liquid fuels used to set standards for the liquid fuel categories. The commenter added that the delegated authority for this facility, North Dakota Department of Health, accepted an applicability determination for the facility to classify the coal derived liquid fuels as the coal/solid-fossil fuel subcategory. This commenter also noted that coal-derived liquid fuels are treated as coal/solid fossils in other related rules such as 40 CFR part 60, subpart Db.

Based on these comments, the EPA is not finalizing any changes to the definition of coal. The definition published on January 31, 2013 (78 FR 7186), remains unchanged. As noted by the commenters, treating coal liquids as coal is consistent with the ICI boiler NSPS (40 CFR part 60, subpart Db), and EPA agrees with the commenters that coal derived liquids are more similar to coal solid fuels than liquid fuels.

E. Other Corrections and Clarifications

In finalizing the rule, the EPA is addressing several other technical corrections and clarifications in the regulatory language based on public comments that were received in response to the January 2015 proposal and other feedback as a result of implementing the rule. In addition to the changes outlined in Table 1 of the January 21, 2015, proposed notice of reconsideration (80 FR 3098), the EPA is finalizing several other changes, as outlined in Table 2 of this preamble.

TABLE 2—SUMMARY OF TECHNICAL CORRECTIONS AND CLARIFICATIONS SINCE JANUARY 2015 PROPOSAL

Section of subpart DDDDD (40 CFR part 63)	Description of correction (40 CFR part 63)
63.7495(h)	• Replaced "January 31, 2016" with "the compliance date of this subpart" to cover sources that might be making changes between January 31, 2016, and the extended compliance date of January 31, 2017.
63.7500(a)(1)	• Fixed the term "common heaters" to "common headers."
63.7515(e)	• Revised to clarify that a source may take multiple samples during a month and the 14-day separation does not apply.
63.7521(g)(2)(ii)	• Replaced the word "notification" with the word "identification" so the sentence reads as follows: "For each anticipated fuel type, the identification of whether you or a fuel supplier will be conducting the fuel specification analysis."
63.7521(g)(2)(vi)	• Revised this paragraph to indicate that, when using a fuel supplier's fuel analysis, the owner or operator is not required to submit the information in 40 CFR 63.7521(g)(2)(iii). Commenters found difficulties when they purchased fuel from another source.
63.7525(a)(2)(vi)	• Language was added because 40 CFR part 75 does not address CO monitoring and does not fully address the moisture correction. *See* section IV.B of the preamble.
63.7525(b) and (b)(1)	• Removed the word certify since PM CPMS does not have a performance specification. *See* section III.C of the preamble.

TABLE 2—SUMMARY OF TECHNICAL CORRECTIONS AND CLARIFICATIONS SINCE JANUARY 2015 PROPOSAL—Continued

Section of subpart DDDDD (40 CFR part 63)	Description of correction (40 CFR part 63)
63.7525(g)(3)	• Revised the paragraph to clarify that the pH monitor is to be calibrated each day and not performance evaluated which is covered in 40 CFR 63.7525(g)(4).
63.7530(c)(3), (c)(4), and (c)(5)	• Revised equations 7, 8, and 9 to clarify that for ''Qi'' the highest content of chlorine, Hg, and TSM is used only for initial compliance and the actual fraction is used for continuous compliance demonstration.
63.7530(d)	• Paragraphs 63.7530(d) and 63.7545(e)(8)(i) contained requirements that were similar in that they both required the submittal of a signed statement or certification of compliance that an initial tune-up of the subject unit has been completed. • Paragraph 63.7530(d) was deleted and 63.7545(e)(8)(i) was modified to clarify that the requirement to include a signed statement that the tune-up was conducted is applicable to all of the boilers and process heaters covered by 40 CFR part 63, subpart DDDDD.
63.7530(e)	• Amended paragraph to clarify that the energy assessment is also considered to have been completed if the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.
63.7540(a)(2)	• Corrected the typographical error in the proposed regulatory text so that it has the proper cross-reference: 40 CFR 63.7555(d).
63.7540(a)(10)(i)	• Revised to provide owners and operators the flexibility to perform burner inspections at any time prior to tune-up.
63.7540(a)(12)	• Revised this paragraph to clarify the O_2 set point for a source not subject to emission limits.
63.7540(a)(14)(i) and (15)(i)	• Clarified the length of the performance test depending on the basis of the rolling average for each operating parameter, for internal rule consistency.
63.7545(e)	• Clarification that notification for these sources is due within 60 days.
63.7545(e)(2)(iii)	• Added a requirement to state the basis of the 30-day rolling average for each operating parameter, for internal rule consistency.
63.7545(e)(8)(i)	• Paragraphs 63.7530(d) and 63.7545(e)(8)(i) contained requirements that were similar in that they both required the submittal of a signed statement or certification of compliance that an initial tune-up of the subject unit has been completed. • Paragraph 63.7530(d) was deleted and 63.7545(e)(8)(i) was modified to clarify that the requirement to include a signed statement that the tune-up was conducted is applicable to all of the boilers and process heaters covered by 40 CFR part 63, subpart DDDDD.
63.7550(b)(1)	• Clarified that the first reporting period for units submitting an annual, biennial, or 5 year compliance report ends on December 31 within 1, 2, or 5 years, as applicable, after the initial compliance date.
63.7550(b)(5)	• Paragraph was included in the March 2011 rule and in the December 2011 reconsideration proposal, but inadvertently removed from the January 2013 final. The text has been reinserted.
63.7550(c)(5)(xvi)	• Clarification that a rolling average is not an arithmetic mean. An arithmetic mean requires more space in a data acquisition system and more effort to review the information for accuracy. Furthermore, the intent is that ALL readings for CEMS and only deviations for non-CEMS are required.
63.7555(d)(11) and (12)	• Text added to clarify that the new requirements apply only if startup definition 2 is selected. • Changed from ''fired'' to ''fed'' to alleviate concerns about units firing solid fuels on a grate or in a FBC where the residual material in the unit keeps burning after fuel feed to the unit is stopped. • Changed from the list of fuels (''coal/solid fossil fuel, biomass/biobased solids, heavy liquid fuel, or gas 2 (other) gases'') to ''fuels that are not clean fuels'' as an acknowledgement that additional clean fuels could be named.
63.7570(b)(1)	• Removed ''non-opacity'' since opacity is not an emission limit, but instead an operating limit. • Added ''except as specified in § 63.7555(d)(13)'' to clarify the procedures for requesting an alternative timeframe with the PM controls requirement to the permitting authority.
63.7575	• Revised definition of energy assessment to include both process heaters and boilers.
63.7575	• Revised definition of minimum sorbent injection rate to clarify that the ratio of sorbent to sulfur applies only to fluidized bed boilers that do not have sorbent injection systems installed.
63.7575	• Revised definition of 30-day rolling average for internal rule consistency. • Revised definition of liquid fuel to remove ''comparable fuels as defined under 40 CFR 261.38.'' This section of the part 261 was vacated by the Court.
63.7575	• Edited definition of operating day and added a definition of rolling average to clarify the procedures for demonstration of compliance.
Table 1 to subpart DDDDD (footnotes c and d)	• Revised footnote ''c'' to change ''January 31, 2013'' to ''April 1, 2013'' to make consistent with effective date of final rule.

TABLE 2—SUMMARY OF TECHNICAL CORRECTIONS AND CLARIFICATIONS SINCE JANUARY 2015 PROPOSAL—Continued

Section of subpart DDDDD (40 CFR part 63)	Description of correction (40 CFR part 63)
	• Revised footnote "d" to clarify that CO concentration on a dry basis corrected to 3-percent O_2 can be calculated using data from the CO_2 CEMS and equations contained in EPA Method 19 instead of an initial compliance test.
	• This revision also applies to footnote "c" in the following tables: Table 2, Table 12, and Table 13 to subpart DDDDD.
Table 4 to subpart DDDDD	• Items 3, 4, and 6, insert "or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation" to be consistent with other operating limits. • Item 7, insert 30-day rolling average before the term "operating load" since the load parameter includes an averaging time. • Added a footnote to clarify that an acid gas scrubber is a control device that uses an alkaline solution.
Tables 4 and 8 to subpart DDDDD	• Continuous compliance is based on monthly fuel analysis and there are no operating limits related to fuel. Fuel analysis language is deleted from Table 4, item 7 and moved to Table 8, line 8.
Table 6 to subpart DDDDD	• Clarification: References to Equations 7, 8, and 9 in 40 CFR 63.7530 are incorrect in items 1.g, 2.g, and 4.g of Table 6. • Move EPA Method 1631, EPA Method 1631E, and EPA 821–R–01–013 from line 1.a to 1.f because these methods cover the analytical method, not the sample collection method. • Remove ASTM D4177 and D4057 from line 1.e and 2.e because these are sampling methods, not methods for determining moisture.
Table 7 to subpart DDDDD (item 5)	• Revised Table 7—item 5 by adding "highest hourly" to resolve an inconsistency with Table 4—item 8 and Table 8—item 10. • Added a footnote to clarify how to set operating parameters when multiple tests are conducted. • Added a footnote to clarify that future tests can confirm operating scenarios.
Table 8 to subpart DDDDD (lines 9.c, 10.c, and 11.c; footnotes).	• Revised to clarify how to set operating parameters, such as load, when multiple performance test conditions are required. The wording in Table 8, lines 9.c, 10.c, and 11.c was revised to be consistent with the wording in lines 2.c, 4.c, 5.c, 6.c, and 7.c.
Table 10 to subpart DDDDD	• For 63.6(g), revised the 3rd column to say "Yes, except § 63.7555(d)(13) specifies the procedure for application and approval of an alternative timeframe with the PM controls requirement in the startup work practice (2)." The edit is consistent with the revision to 40 CFR 63.7555(d)(13). • For 63.6(h)(2) to (h)(9), revised the 3th column to say "No." The edit is consistent with the revision to 40 CFR 63.7570(b).
Table 13 to subpart DDDDD	• Revise the heading to change "January 31, 2013" to "April 1, 2013" to make consistent with effective date of final rule.

V. Other Actions We Are Taking

Section 307(d)(7)(B) of the CAA states that ''[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. If the Administrator refuses to convene such a proceeding, such person may seek review of such refusal in the United States court of appeals for the appropriate circuit (as provided in subsection (b)).''

As to the first procedural criterion for reconsideration, a petitioner must show why the issue could not have been presented during the comment period, either because it was impracticable to raise the issue during that time or because the grounds for the issue arose after the period for public comment (but within 60 days of publication of the final action). The EPA is denying the petitions for reconsideration on a number of issues because this criterion has not been met. In many cases, the petitions reiterate comments made on the proposed December 2011 rule during the public comment period for that rule. On those issues, the EPA responded to those comments in the final rule and made appropriate revisions to the proposed rule after consideration of public comments received. It is well established that an agency may refine its proposed approach without providing an additional opportunity for public comment. *See Community Nutrition Institute* v. *Block,* 749 F.2d at 58 and *International Fabricare Institute* v. *EPA*, 972 F.2d 384, 399 (D.C. Cir. 1992) (notice and comment is not intended to result in ''interminable back-and-forth[,]'' nor is agency required to provide additional opportunity to comment on its response to comments) and *Small Refiner Lead Phase-Down Task Force* v. *EPA*, 705 F.2d 506, 547 (D.C. Cir. 1983) (''notice requirement should not force an agency endlessly to repropose a rule because of minor changes'').

In the EPA's view, an objection is of central relevance to the outcome of the rule only if it provides substantial support for the argument that the promulgated regulation should be revised. *See Union Oil* v. *EPA*, 821 F.2d 768, 683 (D.C. Cir. 1987) (the Court declined to remand the rule because petitioners failed to show substantial likelihood that the final rule would have been changed based on information in the petition). *See* also the EPA's Denial of the Petitions to Reconsider the Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202 of the Clean Air Act, 75 FR at 49556, 49561 (August 13, 2010). *See* also, 75 FR at 49556, 49560–49563 (August 13, 2010) and 76 FR at 4780, 4786–4788 (January 26, 2011) for additional discussion of the standard for reconsideration under CAA section 307(d)(7)(B).

This action includes our final decision to deny the requests for reconsideration with respect to all issues raised in the petitions for reconsideration of the final boiler and process heater rule for which we did not grant reconsideration.

In this final decision, several changes that are corrections, editorial changes, and minor clarifications have been made. These changes made petitioners' comments moot. Therefore, we are denying reconsideration of these issues, as described below.

A. Petitioners' Comments Impacted by Technical Corrections

1. Operating Capacity Limitation

Issue 1: The petitioners (AF&PA, CIBO/ACC) requested that the EPA resolve language conflicts in Tables 4, 7, and 8. Specifically, they claimed there is a conflict as to whether you use the highest hourly average operating load times 1.1 as the operating limit or the test average operating load times 1.1 as the operating limit. The petitioners contended that Table 7 to subpart DDDDD of part 63, item 5 should be revised to clearly state that the limit is set based on the highest hourly average during the performance test times 1.1.

Response to Issue 1: Item 5.c of Table 7 to subpart DDDDD of part 63 has been revised to correctly state, consistent with Tables 4 and 8 to subpart DDDDD of part 63, that the highest hourly average of the three test run averages during the performance test should be multiplied by 1.1 (110 percent) and used as your operating limit. The petitioners' comments are, therefore, now moot and we are denying reconsideration on this issue.

2. Averaging Time for Operating Load Limits

Issue 2: Petitioners (CIBO/ACC) requested clarification of operating load limits. The rule implies that the 110-percent load limit established during a performance test is instantaneous. The area source ICI boiler rule operating load requirement includes a 30-day rolling average period (*see* Table 7 to subpart DDDDD of part 63, Item 9–78 FR 7521). By contrast, the EPA did not add the 30-day rolling average to the Boiler MACT rule operating load requirement (*see* Table 8 to subpart DDDDD of part 63, Item 10–78 FR 7205). The EPA did, however, add the 30-day average to other requirements (*see* Table 8 to subpart DDDDD of part 63, items 2, 4, 5, 6, 7, 9, 11–78 FR 7204–7205).

The petitioners note that operating parameter limits were raised in public comments submitted on the 2013 Boiler MACT. Specifically, a commenter (AF&PA) requested a change be made in Table 4 to subpart DDDDD of part 63, item 8 (add ''30-day average'' prior to ''operating load''). The operating parameter ranges are established using test data obtained at steady state, so a 30-day averaging period allows for some fluctuations that will occur over the range of operating conditions.

Response to Issue 2: Table 8 to subpart DDDDD of part 63 has been amended to clarify that operating load compliance is demonstrated with a 30-day average, as specified in 40 CFR 63.7525(d). Table 4 to subpart DDDDD of part 63, item 7 (previously item 8 as noted by the petitioner), has also been clarified to reflect that the affected source must maintain the 30-day rolling average operating load of each unit. The petitioners' comments are, therefore, now moot and we are denying reconsideration on this issue.

3. A Gas Fired Boiler, Capacity >25MW, Is an EGU, It Is Not Subject to UUUUU, and Should Not Be Subject to the Boiler MACT

Issue 3: Petitioners (UARG/NHPC) alleged that the EPA has broadened the applicability of 40 CFR part 63, subpart DDDDD with regard to EGUs by stating that only ''[a]n electric utility steam generating unit (EGU) covered by subpart UUUUU of [part 63]'' is ''not subject to'' the Boiler MACT. Because 40 CFR part 63, subpart UUUUU does not cover all EGUs, the language in 40 CFR 63.7491(a) seems unlawful because it suggests that some boilers that are EGUs could be subject to 40 CFR part 63, subpart DDDDD. Under 40 CFR 63.9983(b), natural gas-fired EGUs (as defined in 40 CFR part 63, subpart UUUUU) are not subject to 40 CFR part 63, subpart UUUUU, but would not seem to be exempt from 40 CFR part 63, subpart DDDDD. Narrowing the exclusion in 40 CFR 63.7491(a) cannot be a ''logical outgrowth'' of the proposed rule.

The petitioners point out that ''Natural gas-fired electric utility steam generating unit'' is defined in 40 CFR part 63, subpart UUUUU as ''an electric utility steam generating unit meeting the definition of 'fossil fuel-fired' that is not a coal-fired, oil-fired, or integrated gasification combined cycle (IGCC) electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year'' 40 CFR 63.10042. As a result, natural gas-fired EGUs for purposes of 40 CFR part 63, subpart UUUUU include those units that combust only natural gas as well as those units that combust natural gas for more than the proportion(s) specified in 40 CFR 63.10042 and some other fuel(s) (*e.g.,* oil) for the remainder of heat input, as long as they are not an IGCC unit and do not combust coal or oil in sufficient quantity to meet the definition of ''coal-fired'' or ''oil-fired'' EGU.

The petitioners refer to CAA section 112(n)(1)(A), which requires the EPA to conduct a health study of the effects of EGU HAP emissions prior to regulating HAP emissions from EGUs under CAA section 112. Then, if EGU HAP emissions pose a threat to public health, the EPA can regulate those emissions only as ''appropriate and necessary.'' The EPA already has regulated under 40 CFR part 63, subpart UUUUU all those EGUs for which the Administrator has made the statutorily required finding under CAA section 112(n)(1)(A)—*i.e.,* coal-fired and oil-fired EGUs; the EPA has no basis to regulate any other EGU under 40 CFR part 63, subpart DDDDD. That conclusion is consistent with the EPA's March 21, 2011, final rule and proposed rule on reconsideration, both of which made clear that no boiler meeting the definition of EGU was subject to 40 CFR part 63, subpart DDDDD.

Petitioners also allege that issues regarding the EGU definition in 40 CFR part 63, subpart DDDDD were raised in public comments submitted on the 2013 Boiler MACT. Specifically, the commenter (UARG) requested that the EGU definition in 40 CFR part 63, subpart DDDDD be consistent with relevant definitions in 40 CFR part 63, subpart UUUUU, and remain that way even after the EPA finalizes its revisions to 40 CFR part 63, subpart UUUUU. The EPA should revise the definition in 40 CFR 63.7575 of subpart DDDDD to incorporate, rather than restate, the definition of applicable ''fossil fuel-fired'' EGU in 40 CFR 63.10042 of the MATS rule.

Response to Issue 3: As stated in the June 2010 proposal (75 FR 32016), it is and has always been the EPA's intent that biomass boilers are regulated under either the Boiler MACT or the area source ICI boiler rules. The 2010 Boiler MACT proposal stated:

> The CAA specifically requires that fossil fuel-fired steam generating units of more than 25 megawatts that produce electricity for sale (*i.e.,* utility boilers) be reviewed separately by EPA. Consequently, this proposed rule would not regulate fossil fuel-fired utility boilers greater than 25 megawatts, but would regulate fossil fuel-fired units less than 25 megawatts and all utility boilers firing a non-fossil fuel that is not a solid waste.

The Boiler MACT defines the biomass/bio-based solid subcategory as any boiler or process heater that burns at least 10-percent biomass or bio-based solids on an annual heat input basis. The EPA disagrees with the commenter who recommends that EPA simply adopt provisions from the MATS rule into the Boiler MACT rule. We considered what would be the maximum amount of fuel that can be co-fired in a boiler that is designed to burn a different fuel type. We are aware that boilers are designed for specific fuel types and will frequently encounter operational problems if a fuel with characteristics other than those originally specified is fired in amounts above a certain level. The purpose of 63.7491(a) is, in part, to identify a threshold of natural gas operation above which EPA is reasonably certain that the unit is designed to operate on natural gas. At a level below that threshold, the EPA cannot be certain that the unit is not of a different type, designed to burn other fuels. In this final rule, the EPA edited text in 40 CFR 63.7491(a) from ''An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part or a natural gas-fired EGU as defined in subpart UUUUU of this part firing at least 90 percent natural gas on an annual heat input basis.'' to ''. . . at least . . . 85 percent . . .'' This change was made to address variation in heat input of biomass fuels. This clarification does not change the underlying applicability of biomass EGU boilers under the Boiler MACT rule.

With respect to the petitioners' reference to CAA section 112(n)(1)(A), the EPA disagrees that this provision is relevant here, as biomass boilers are not EGUs, but instead are classified as ICI boilers. Therefore, because the petitioners did not demonstrate that it was impracticable to comment on this issue during the comment period on the 2010 proposed rule, the EPA is denying reconsideration on this issue.

4. Use of the Publication Date Rather Than the Effective Date of the Rule To Establish Various Compliance and Reporting Dates

Issue 4: Petitioner (API) alleged that the compliance schedules are based on the date of publication rather than the effective date. Using the publication date rather than the effective date conflicts with certain CAA provisions and certain 40 CFR, part 63 general provisions.

Response to Issue 4: With respect to existing units, the petitioner's allegation is incorrect. Section 112(i)(3)(A) of the CAA states ''After the effective date of any emission standard . . . the Administrator shall establish a compliance date . . . for . . . existing source, which shall provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date . . .'' However, it is appropriate that compliance provisions applicable to new units should be based on the effective date because, otherwise, as stated in 40 CFR 63.7495(a), new units would be required to comply with the subpart by the publication date even though the amendments have not yet taken effect. Wherever January 31, 2013, was specified for new affected units as a compliance date or a basis for compliance activity, the date has been revised to April 1, 2013. The petitioner's comments are, therefore, now moot and we are denying reconsideration on this issue.

5. Existing EGUs That Become Subject to the Boiler MACT After January 31, 2013 Do Not Get the Intended 180-Day Period for Demonstrating Compliance

Issue 5: Petitioner (UARG, supplemental July 3, 2013, petition) objected to the language in 40 CFR 63.7510(i), which states that ''For an existing EGU that becomes subject after January 31, 2013, you must demonstrate compliance within 180 days after becoming an affected source'' (78 FR 7165). The petitioner argued the provision is inconsistent with the existing source compliance dates in 40 CFR 63.7495(b) and (f), which require compliance by January 31, 2016, and the existing source deadline for demonstrating compliance in 40 CFR 63.7510(e), which requires completion of the initial compliance demonstration within 180 days after the January 31, 2016, compliance date (78 FR at 7162–63, 7165).

Response to Issue 5: For consistency and to correct the inadvertent error of failing to change the date, the compliance date in 40 CFR 63.7510(i) has been revised from 2013 to 2016. The petitioner's comments are, therefore, now moot and we are denying reconsideration on this issue.

6. Using Fuel Analysis Rather Than Performance Testing Required Use of the 90th Percentile Confidence Level; a Monthly Average Is More Appropriate

Issue 6: Petitioner (Eastman) requested clarification of the methodology that provides facilities with multiple combustion units the ability to demonstrate compliance with the limits through emissions averaging across affected units. Specifically, the petitioner urged modification of Table 6 to 40 CFR part 63, subpart DDDDD to delete references to equations requiring use of the 90th percentile.

Response to Issue 6: Edits to Table 6 to subpart DDDDD of 40 CFR part 63 have been made to delete the inadvertent references to equations requiring the use of the 90th percentile. These equations are required only for determining initial compliance as specified in 40 CFR 63.7530(c). The petitioner's comments are, therefore, now moot and we are denying reconsideration on this issue.

7. Gas 1 Unit Requirements

Issue 7: Petitioner (CIBO/NEDACAP) alleged that to meet 40 CFR 63.7555(i) and (j) recordkeeping requirements, each regulated gas 1 boiler, regardless of size, needs electronic controls, a recording device, individual gas meters, and sensors to detect both steam/hot water flow and fuel cycling events. The petitioner further claimed that records of startup and shutdown for gas 1 units are irrelevant to emission control or enforcement of the Boiler MACT requirements because their installation and operation provide no environmental benefits.

Response to Issue 7: The startup and shutdown recordkeeping provisions in 40 CFR 63.7555(i) and (j) have been removed. These paragraphs were inadvertently not deleted when the rule was amended. These paragraphs were intended to be deleted because 40 CFR 63.7555(d) was amended incorporating these recordkeeping requirements. These recordkeeping requirements are intended only for sources subject to emission standards, whereas 40 CFR 63.7555(i) and (j) have the unintended purpose of requiring sources not subject to emission standards to startup and shutdown recordkeeping requirements. The petitioner's comments are, therefore, now moot and we are denying reconsideration on this issue.

8. Gas 1 Reporting Requirements

Issue 8: Petitioner (CIBO/NEDACAP) asked for clarity with respect to the operating time reporting in 40 CFR 63.7550(c)(5)(iv) for gas 1 units. Specifically, ''operating time'' is not a defined term and it is unclear whether operating time must be reported separately for each unit. Furthermore, the petitioner alleged that operating time (like records of startup and shutdown) adds no information that is useful in determining compliance, nor is it useful in calculating emissions from reported units, since emissions are related to fuel combusted, not to total operating time.

Response to Issue 8: Operating time reporting in 40 CFR 63.7550(c)(5)(iv) has been removed from 40 CFR 63.7550(c)(1), which effectively removes the reporting requirement for gas 1 units. The petitioner's comments are, therefore, now moot and we are denying reconsideration on this issue.

9. Sampling for Other Gas 1 Fuels

Issue 9: Petitioner (CIBO/NEDACAP) asked for clarifying text in 40 CFR 62.7521 to parallel Table 6 to subpart DDDDD of part 63, item 3.b alternative compliance approach for cases where sampling and analysis of the fuel gas itself are not possible or practical.

Response to Issue 9: Text describing the compliance procedures, applicable to other gas 1 fuels in 40 CFR 63.7521(f), has been amended as a technical correction. When the rule was amended the EPA added a second compliance procedure that was intended to be an alternative approach but the amendments inadvertently failed to add the ''or'' after the first compliance procedure. The petitioner's comments are, therefore, now moot and we are denying reconsideration on this issue.

10. Fuel Analysis Plan for Gas 1 Sampling

Issue 10: Petitioner (CIBO/NEDACAP) alleged that the Fuel Analysis Plan requirements for other gas 1 fuels are more onerous than those required for solid and liquid fuels. There is no logical reason to require submission of the fuel analysis plan to the Administrator for review and approval for other gas 1 fuels when only alternative analytical methods listed in Table 6 to subpart DDDDD of part 63 are used; 40 CFR 63.7521(g) should be amended.

Response to Issue 10: Administrator review and approval for other gas 1 fuels requirement in 40 CFR 63.7521(g) has been revised to clarify the intended scope of the Fuel Analysis Plan requirements and to be consistent with 40 CFR 63.7521(b)(1). As specified in 40 CFR 63.7521(b)(1), a fuel analysis plan is required to be submitted for Administrator review and approval only when alternative methods other than those listed in Table 6 to subpart DDDDD of part 63 are used. The petitioner's comments are, therefore, now moot and we are denying reconsideration on this issue.

11. Affirmative Defense

Issue 11: Petitioner (FSI) asked that the EPA amend the affirmative defense provisions included in 40 CFR 63.7501 or otherwise clarify in the rule the scope of the affirmative defense for violations that occur during malfunctions. The petitioner also asked that subpart A of 40 CFR part 63, which defines emission standard as ''a national standard, limitation, prohibition, or other regulation promulgated in a subpart of this part pursuant to sections 112(d), 112(h), or 112(f) of the Act,'' provide additional guidance concerning the proper interpretation of 40 CFR 63.7501.

Response to Issue 11: The EPA has removed affirmative defense provisions from 40 CFR part 63, subpart DDDDD, as discussed in section IV.C of this preamble. Because the petitioner has not demonstrated that it was impracticable to comment on this issue during the public comment period on the December 2011 proposed rule, and because the issue is now moot, the EPA is denying this petition.

B. Petitions Related to Ongoing Litigation

1. Authority To Require an Energy Assessment

Issue 12: Petitioners (AF&PA/FSI) alleged that a beyond the floor requirement of an energy assessment is outside EPA's authority for setting emissions standards under CAA section 112(d)(1) ''for each category or subcategory of major sources and area sources.'' The EPA has defined the source category for these rules to include only specified types of boilers and process heaters and, therefore, those are the only sources for which the EPA may set standards under these rules.

The petitioners also alleged that the energy assessment requirement is not an ''emissions standard'' as that term is defined in the CAA and, therefore, the EPA does not have authority to prescribe such requirements. Furthermore, as a practical matter, even if energy efficiency projects are implemented, there is no guarantee that there will be a corresponding reduction in HAP emissions from affected boilers and process heaters.

Response to Issue 12: Petitioners have not demonstrated that it was impracticable to comment on these issues during the public comment period on the proposed Boiler MACT. In fact, petitioners provided the same comments during that comment period, and subsequently challenged EPA's establishment of the energy assessment requirement. That issue is currently pending before the Court in *U.S. Sugar* v. *EPA* (No. 11–1108). Therefore the EPA is denying the petition for reconsideration of this issue.

2. Energy Assessment Requirement

Issue 13: Issues regarding the owner or operator obligations after the energy assessment is completed were raised in public comments submitted on the 2013 Boiler MACT. Specifically, commenters (AF&PA/FSI) asked that the EPA confirm that the Boiler MACT does not require a facility owner or operator to implement any of the recommendations contained in the energy assessment report.

Response to Issue 13: Comments on this issue have been previously submitted and the EPA responded to those comments. AF&PA made this same comment during the public comment period on the Boiler MACT, and the EPA responded to that in the Beyond-the-Floor Analysis Section (pp. 1428–1702) of the February 2011 Response To Comment document, explaining that the rule does not require owners and operators to implement the recommendations of the energy assessment, but that the EPA expects that sources will do so in order to realize the cost savings from those recommendations. Because petitioners have not demonstrated that it was impracticable to comment on these issues during the public comment period on the proposed Boiler MACT, the EPA is denying the petition for reconsideration of this issue.

C. Other Petitions

1. Expanded Exemption for Limited Use Units

Issue 14: Petitioner (Sierra Club) objected to the 2013 Boiler MACT proposed rule, which revised the definition of ''limited-use units'' to include all units that operate at 10 percent of their full annual capacity (78 FR 7144). A unit that operated full time at 10-percent capacity would qualify, as would a unit that operated for one-third of the year at 30-percent capacity. The petitioner also disputed the EPA's finding that ''it is technically infeasible to schedule stack testing for these limited use units since these units serve as back up energy sources and their operating schedules can be intermittent and unpredictable.''

Response to Issue 14: The EPA is denying the petition for reconsideration on this issue because the petitioner previously submitted comments on this issue, and the EPA responded to those comments in finalizing the definition of a limited use unit at that time (76 FR 15633, March 21, 2011).

The 2013 revision in the final amendments to the Boiler MACT was a logical outgrowth of the comments received during the public comment period. *See NRDC* v. *Thomas,* 838 F.2d 1224, 1242 (D.C. Cir. 1988) and *Small Refiner Lead Phase-Down Task Force* v. *EPA,* 705 F.2d at 547 (the agency may make changes to proposed rule without triggering new round of comments, where changes are logical outgrowth of proposal and comments).

2. Failure to Set Standards Requiring MACT (*i.e.,* Beyond the Floor)

Issue 15: Petitioner (Sierra Club) asserted that the EPA failed to assure that the standards it revised in the final rule reflect the maximum achievable degree of reduction in emissions, as required by CAA section 112(d)(2). The commenter noted that for existing sources, 10 of the Hg standards, five of the PM standards, and 11 of the CO limits were revised in the final rule. The petitioner also noted that two of the PM limits and 11 of the CO limits for new sources were weakened in the final rule. The petitioner asserted that the EPA did not propose any of these changes, nor did it discuss them in its proposed rule (78 FR 7145).

Response to Issue 15: The EPA is denying the petition for reconsideration on this issue because the changes to the standards between the 2011 and 2013 final rules were based only on changes to the underlying dataset to reflect unit shutdowns or corrections to emission test run data and on changes made to the subcategories after consideration of comments received on the proposed rule. These changes were discussed in the MACT Floor Memorandum for the final rule (*See* Docket ID No.: EPA–HQ–2002–0058–3836), as well as documented in the database for the final rule (See Docket ID No.: EPA–HQ–OAR–2002–0058–3835). There were no significant changes to the methodology used to calculate the MACT standards. Therefore, the petition does not raise an issue of central relevance to this rulemaking as it does not demonstrate that there is a substantial likelihood that the final rule would have changed based on the information in the petition.

3. Beyond the Floor PM Standards

Issue 16: The petitioner (Sierra Club) objected to the EPA's final ''beyond the floor'' PM standards for certain categories of new biomass units. The petitioner claimed that the EPA did not provide an explanation of its conclusion that ''[w]e did not identify any beyond the floor options for existing source PM limits or new and existing limits for other pollutants as technically feasible or cost effective'' (78 FR 7145). The petitioner alleged that such cursory and unexplained conclusion that no beyond the floor standards are technically feasible or cost effective is both unlawful and arbitrary. Moreover, the petitioner also alleges that because the EPA did not propose the standards contained in the 2013 rule and did not discuss changing the level of these standards in its proposed rule, it was ''impracticable'' to object to the EPA's failure to set more stringent standards during the public comment period. 42 United States Code (U.S.C.) 7607(d)(7)(B). Likewise, the petitioner indicated it was impracticable to object to the EPA's rationale for not setting more stringent standards.

Response to Issue 16: The EPA disagrees with the petitioner's claim that we failed to set standards based on the degree of emission reduction that can be achieved. The EPA must consider cost, non-air quality health and environmental impacts, and energy requirements in connection with any standards that are more stringent than the MACT floor (beyond the floor controls). The EPA's beyond the floor analysis did evaluate these factors in determining PM standards for certain categories of new biomass units.

To the extent the petitioner is concerned about the degree of emission reduction that can be achieved, that issue does not warrant reconsideration. The EPA made changes based on new data and changes to subcategories, but the methodology essentially remained the same, including the beyond the floor methodology in the final rule. The petitioner did not provide data or information that was unavailable at the time the EPA proposed the rule. Therefore, the EPA is denying reconsideration of this issue.

4. No Allowance for Liquid Firing in Gas 1 or Gas 2 Units; Other Subcategories Allow for Less Than 10 Percent Annual Heat Input

Issue 17: Petitioners (API, CIBO/ACC) contended that the gas 1 subcategory should place no restriction on liquid (*e.g.,* oil) firing during startup. In the 2013 final amendments to the Boiler MACT, there is no allowance for liquid fuel firing in units in the gas 1 or gas 2 subcategories except under the gas curtailment or interruption provisions, whereas other subcategories allow use of liquid fuels for less than 10-percent annual heat input basis (78 FR 7193). The definition for the gas 1 subcategory should read ''Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns at least 90-percent natural gas, refinery gas, and/or other gas 1 fuels on a heat input basis on an annual average and less than 10 percent of any solid or liquid fuel.'' The definitional change would simplify the process of determining whether a unit qualifies for the gas 1 subcategory.

Issues regarding the consistency between the exempt unit description in 40 CFR part 63, subpart DDDDD and the definition of an oil-fired EGU in 40 CFR part 63, subpart UUUUU were raised in public comments submitted on the 2013 Boiler MACT. Specifically, a commenter (DTE Energy) argued that subpart UUUUU allows for ''high'' usage in one calendar year without becoming an affected unit so long as the 10-percent annual average heat input during 3 consecutive calendar years is not exceeded.

Response to Issue 17: Because the EPA received comments that gas 1 subcategory units should allow for limited use of liquid fuel in the June 4, 2010, proposal and petitioners have not demonstrated that it was impractical for them to comment, we are denying the petition for reconsideration on this issue.

In addition, the petitioners have provided no new data or information that calls into question the underlying determination.

5. Refine and Clarify the Scope of the Subcategory for Hybrid Suspension/Grate Boilers

Issue 18: Petitioner (SugarCane Growers) asked that the definition of a hybrid suspension/grate (HSG) boiler needs clarification; there are facilities that are unsure whether their boilers fit within the HSG subcategory. Specifically, the petitioner requested that the definition add a phrase referring to the fact that an HSG boiler is ''highly integrated into the production process via steam connections with the sugar mill and the boiler primarily combusts fuels that are generated on-site by the mill.''

Response to Issue 18: The EPA has made a minor technical correction to the final HSG boiler definition that helps clarify the intent of the subcategory. The moisture content threshold of 40 percent on an as-fired annual heat input basis is to be demonstrated by monthly fuel analysis. By requiring demonstration on a monthly fuel analysis, the moisture in the fuel piles will need to be consistently high from month to month in order to meet the 40 percent moisture threshold. Beyond this minor clarification, the EPA is denying this petition for reconsideration because the petition does not demonstrate that the petitioner lacked the opportunity to comment on this definition, and we continue to believe that the definition is specifically clear as to whether specific boilers fit within the definition. The definition reflects a logical outgrowth of the comments received during the comment period. (see 76 FR 15634, March 21, 2011).

6. Applicability Based on Commercial and Industrial Solid Waste Incineration (CISWI) Recordkeeping Requirements

Issue 19: The petitioner (API) alleged that it is unreasonable to have Boiler MACT applicability determined based on a recordkeeping requirements contained in the CISWI rule, and added that nothing in the Boiler MACT proposal requested comment on the CISWI definition of traditional fuels. The petitioner alleged that any unit that uses any material not specifically listed in the traditional fuels definition is a CISWI unit, rather than a Boiler MACT unit, unless it keeps specific records that the CISWI rule requires. The definitions of CISWI unit in the February 7, 2013, final amendments to the CISWI NSPS standard and the associated emission guideline include the sentence ''If the operating unit burns materials other than traditional fuels as defined in § 241.2 that have been discarded, and you do not keep and produce records as required by [§ 60.2740(u) or § 60.2175(v)], the operating unit is a CISWI unit.''

Response to Issue 19: The EPA is denying this petition because it is not of central relevance. The issue addresses recordkeeping requirements in the CISWI rule, not requirements in the Boiler MACT. To ensure that owners or operators of units combusting materials review and apply the non-waste provisions in the Solid Waste Definition Rule, the EPA requires owners or operators that combust materials that are not clearly listed as traditional fuels document how the materials meet the legitimacy criteria and/or the processing requirements in the Solid Waste Definition Rule. Failure of a source owner or operator to correctly apply the non-waste criteria would result in incorrect self-assessments as to whether their combustion units are subject to CISWI. Requiring sources to document how the non-waste criteria apply to the materials combusted will both improve self-assessments of applicability, and will assist the EPA and states in the proper identification of sources subject to CISWI.

7. Definitions for Rolling Averages Are Inconsistent With Other Rule Requirements, and Increase Burdens

Issue 20: The petitioner (API) alleged that both 10- and 30-day rolling average definitions, if read literally, say owners or operators must average a total of 240 or 720 hours of valid data, regardless of the calendar period they span, rather than requiring that only hours within the last 240 or 720 calendar hours that contain valid data be averaged. As a result, since the number of hours of valid data over any calendar period is constantly varying, the time period covered by each average will vary. Individual hours will be counted in varying numbers of averages, and all units at a facility will end up on different, constantly varying averaging schedules. This approach is also inconsistent with the definition of ''daily block average,'' which calls for averaging all valid data occurring within each daily 24-hour period and includes other averaging requirements. Revisions to the definitions of 10-day rolling average and 30-day rolling average should be amended.

Response to Issue 20: The EPA is denying this petition because it is not of central relevance to this rulemaking for the reasons set forth below. The definitions of 10- and 30-day rolling averages include the word ''valid.'' Valid data excludes hours during startup and shutdown and data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan. Further, the 30-day rolling average for CO CEMS has been revised to clarify that for CO CEMS, the 720 hours should be consecutive, but not necessarily continuous to reflect intermittent operations.

8. CO Limits for Hybrid Suspension Grate Boilers

Issue 21: The petitioner (FSI) alleged that the CO CEMS emission limit for existing HSG boilers is set at the same level as the CO CEMS limit for new HSG boilers, because the EPA has CO CEMS data for only one HSG boiler. The CO CEMS limit for existing boilers should be revised to account for the variability in the emissions data for existing HSG boilers, as reflected by the EPA's stack test data for such boilers.

Response to Issue 21: CO CEM data were only available for one unit. Therefore, the alternative CO CEMS-based limit is the same for both new and existing units. The petitioner could have provided additional data to the EPA prior to the close of the comment period for the final rule. Indeed, the EPA modified several emission limits upon receipt of new data. Setting emission limits based on available data is consistent with MACT floor methodology. Therefore, the EPA is denying the petition for reconsideration.

9. Correction of Math Error

Issue 22: The petitioner (FSI) alleged that a math (*i.e.,* conversion) error was committed when converting stack test data within the EPA's emissions database. According to the petitioner, this error significantly affected the EPA's determination of the MACT floor for CO emissions from the existing HSG boilers. The petitioner stated that the EPA should correct this error and then use its existing emissions database to re-determine the CO emission limit for existing HSG boilers. The petitioner calculated a revised CO emission limit for existing HSG boilers of 3,500 ppm by dry volume at 3-percent O_2.

Response to Issue 22: As discussed in section IV.E of this preamble, the EPA has finalized the correction to the CO limit for this subcategory.

10. Conducting Tune-ups at Seasonally Operated Boilers

Issue 23: The petitioner (FSI) alleged that collecting meaningful CO data before and after an annual tune-up will be problematic because HSG boilers are operated on a seasonal basis and the annual tune-ups will be performed between the annual harvest seasons. With regard to these seasonally operated boilers, the Boiler MACT should explicitly acknowledge that the ''before'' measurement will be taken at the end of one harvest season and the ''after'' measurement will be taken at the beginning of a different harvest.

Response to Issue 23: The EPA is denying reconsideration on this issue. The EPA believes the rule is sufficiently clear on the timing of a tune-up and refers the petitioner to 40 CFR 63.7540(a)(10). If the unit is not operating on the required date for a tune-up (*i.e.,* because it is a seasonal boiler, or because it is down for maintenance, for example), the tune-up must be conducted within 30 days of startup. Before and after measurements are not seasons apart, instead they are within minutes or hours (depending on how long it takes to make adjustments). *See* the tune-up guide for additional guidance (*http://www.epa.gov/ttn/atw/boiler/imptools/boiler_tune-up_guide-v1.pdf*).

VI. Impacts of This Final Rule

This action finalizes certain provisions and makes technical and clarifying corrections, but does not promulgate substantive changes to the January 2013 final Boiler MACT (78 FR 7138). Therefore, there are no environmental, energy, or economic impacts associated with this final action. The impacts associated with the Boiler MACT are discussed in detail in the January 2013 final amendments to the Boiler MACT.

VII. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.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 not a significant regulatory action and was, therefore, not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

This action does not impose any new information collection burden under the PRA. OMB has previously approved the information collection activities contained in the existing regulations (40 CFR part 63, subpart DDDDD) and has assigned OMB control number 2060–0551. This action is believed to result in no changes to the information collection requirements of the January 2013 final amendments to the Boiler MACT, so that the information collection estimate of project cost and hour burden from the final Boiler MACT have not been revised.

C. 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. This action finalizes the EPA's response to petitions for reconsideration on three issues of the Boiler MACT as well as minor changes to the rule to correct and clarify implementation issues raised by stakeholders.

D. 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. This rule promulgates amendments to the January 2013 final Boiler MACT provisions, but the amendments are mainly clarifications to existing rule language to aid in implementation, or are being made to maintain consistency with other, more recent, regulatory actions. Therefore, the action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

E. 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.

F. 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. This action clarifies certain components of the January 2013 final Boiler MACT. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only 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 any such environmental health risks or safety risks.

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

This action is not subject to Executive Order 13211 because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

This action does not involve any new technical standards from those contained in the March 21, 2011, final rule. Therefore, the EPA did not consider the use of any voluntary consensus standards. *See* 76 FR 15660–15662 for the NTTAA discussion in the March 21, 2011, final rule.

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

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income, or indigenous populations because it does not affect the level of protection provided to human health or the environment.

The environmental justice finding in the January 2013 final amendments to the Boiler MACT remain relevant in this action, which finalizes three aspects of the Boiler MACT as well as finalizing minor changes to the rule to correct and clarify implementation issues raised by stakeholders.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a "major rule" as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances.

Dated: November 5, 2015.

Gina McCarthy,

Administrator.

For the reasons cited in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is amended as follows:

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

■ 1. The authority for part 63 continues to read as follows:

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

Subpart DDDDD—[Amended]

■ 2. Section 63.7491 is amended by revising paragraphs (a), (j), and (l) and adding paragraph (n) to read as follows:

§ 63.7491 Are any boilers or process heaters not subject to this subpart?

* * * * *

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part or a natural gas-fired EGU as defined in subpart UUUUU of this part firing at least 85 percent natural gas on an annual heat input basis.

* * * * *

(j) Temporary boilers and process heaters as defined in this subpart.

* * * * *

(l) Any boiler or process heater specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

* * * * *

(n) Residential boilers as defined in this subpart.

■ 3. Section 63.7495 is amended by revising paragraphs (a), (e), and (f) and adding paragraphs (h) and (i) to read as follows:

§ 63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by April 1, 2013, or upon startup of your boiler or process heater, whichever is later.

* * * * *

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of § 60.2145(a)(2) and (3) or § 60.2710(a)(2) and (3).

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2016, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

* * * * *

(h) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory after the compliance date of this subpart, you must be in compliance with the applicable existing source provisions of this subpart on the effective date of the fuel switch or physical change.

(i) If you own or operate a new industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory, you must be in compliance with the applicable new source provisions of this subpart on the effective date of the fuel switch or physical change.

■ 4. Section 63.7500 is amended by revising paragraphs (a)(1) introductory text, (a)(1)(ii), (a)(1)(iii), and (f) to read as follows:

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

(a) * * *

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 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 (iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

* * * * *

(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 1 or 12 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 1 or 13 to this subpart until January 31, 2016.

* * * * *

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with items 5 and 6 of Table 3 to this subpart.

§ 63.7501 [Removed and Reserved]

■ 5. Section 63.7501 is removed and reserved.

■ 6. Section 63.7505 is amended by revising paragraphs (a), (c), and (d) introductory text and adding paragraph (e) to read as follows:

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

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These emission and operating limits apply to you at all times the affected unit is operating except for the periods noted in § 63.7500(f).

* * * * *

(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), 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 13 to this subpart.

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits through the use of CPMS, or with a CEMS or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

* * * * *

(e) If you have an applicable emission limit, and you choose to comply using definition (2) of ''startup'' in § 63.7575, you must develop and implement a written startup and shutdown plan (SSP) according to the requirements in Table 3 to this subpart. The SSP must be maintained onsite and available upon request for public inspection.

■ 7. Section 63.7510 is amended by revising paragraphs (a) introductory text, (a)(2)(ii), (c), (e), (g), and (i) and adding paragraph (k) 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 13 of this subpart through performance (stack) testing, your initial compliance requirements include all the following:

* * * * *

(2) * * *

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those Gas 1 fuels according to § 63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those non-Gas 1 gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those non-Gas 1 fuels according to § 63.7521 and Table 6 to this subpart.

* * * * *

(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 13 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.

* * * * *

(e) For existing affected sources (as defined in § 63.7490), you must complete the initial compliance demonstrations, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in § 63.7495 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in § 63.7495.

* * * * *

(g) For new or reconstructed affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in § 63.7515(d) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7515(d).

* * * * *

(i) For an existing EGU that becomes subject after January 31, 2016, you must demonstrate compliance within 180 days after becoming an affected source.

* * * * *

(k) For affected sources, as defined in § 63.7490, that switch subcategories consistent with § 63.7545(h) after the initial compliance date, you must demonstrate compliance within 60 days of the effective date of the switch, unless you had previously conducted your compliance demonstration for this subcategory within the previous 12 months.

■ 8. Section 63.7515 is amended by revising paragraphs (d), (e), and (h) to read as follows:

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

* * * * *

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to § 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in § 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in § 63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after April 1, 2013 or the initial startup of the new or reconstructed affected source, whichever is later.

(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 13 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 one 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.

* * * * *

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra-low sulfur liquid fuel, you do not need to conduct further performance tests (stack tests or fuel analyses) if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra-low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

* * * * *

■ 9. Section 63.7521 is amended by:

■ a. Revising paragraph (a).

■ b. Revising paragraph (c) introductory text.
■ c. Revising paragraph (c)(1)(ii).
■ d. Revising paragraph (f) introductory text.
■ e. Revising paragraphs (g) introductory text, (g)(2)(ii), and (g)(2)(vi).
■ f. Revising paragraph (h).

The revisions 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 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section.

* * * * *

(c) You must obtain composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material. At a minimum, for demonstrating initial compliance by fuel analysis, you must obtain three composite samples. For monthly fuel analyses, at a minimum, you must obtain a single composite sample. For fuel analyses as part of a performance stack test, as specified in § 63.7510(a), you must obtain a composite fuel sample during each performance test run.

(1) * * *

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

* * * * *

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section, or as an alternative where fuel specification analysis is not practical, you must measure mercury concentration in the exhaust gas when firing only the gaseous fuel to be demonstrated as an other gas 1 fuel in the boiler or process heater according to the procedures in Table 6 to this subpart.

* * * * *

(g) You must develop a site-specific fuel analysis plan for other gas 1 fuels according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

* * * * *

(2) * * *

(ii) For each anticipated fuel type, the identification of whether you or a fuel supplier will be conducting the fuel specification analysis.

* * * * *

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart. When using a fuel supplier's fuel analysis, the owner or operator is not required to submit the information in § 63.7521(g)(2)(iii).

(h) You must obtain a single fuel sample for each fuel type for fuel specification of gaseous fuels.

* * * * *

■ 10. Section 63.7522 is amended by:
■ a. Revising paragraphs (c), (d), (f)(1) introductory text, (g)(1), (g)(3) introductory text, and (i).
■ b. Revising parameters ''En'' and ''ELi'' of Equation 6 in paragraph (j)(1).

The revisions read as follows:

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

* * * * *

(c) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on April 1, 2013 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on April 1, 2013.

(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 to this subpart at all times the affected units are subject to numeric emission limits following the compliance date specified in § 63.7495.

* * * * *

(f) * * *

(1) For each calendar month, you must use Equation 3a or 3b or 3c of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you are complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual electrical generation for the month if you are complying with the emission limits on an electrical generation (output) basis.

* * * * *

(g) * * *

(1) If requested, you must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

* * * * *

(3) If submitted upon request, the Administrator shall review and approve or disapprove the plan according to the following criteria:

* * * * *

(i) For a group of two or more existing units in the same subcategory, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) * * *

(1) * * *

* * * * *

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu) or parts per million (ppm).

Eli = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu or ppm.

* * * * *

■ 11. Section 63.7525 is amended by:

■ a. Revising paragraphs (a) introductory text, (a)(1), (a)(2) introductory text, (a)(3), and (a)(5).

■ b. Adding paragraph (a)(2)(vi).

■ c. Revising paragraphs (b) introductory text, (b)(1) introductory text, and (b)(1)(iii).

■ d. Revising paragraphs (g)(3) and (4).

■ e. Revising paragraphs (m) introductory text and (m)(2).

The revisions and addition 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 13 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.

(1) Install the CO CEMS and oxygen (or CO_2) analyzer by the compliance date specified in § 63.7495. The CO and oxygen (or CO_2) levels shall be monitored at the same location at the outlet of the boiler or process heater. An owner or operator may request an alternative test method under § 63.7 of this chapter, in order that compliance with the CO 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.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 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 13 to this subpart.

* * * * *

(vi) When CO_2 is used to correct CO emissions and CO_2 is measured on a wet basis, correct for moisture as follows: Install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases, in order to correct the measured hourly volumetric flow rates for moisture when calculating CO concentrations. The following continuous moisture monitoring systems are acceptable: A continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O_2 both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, *i.e.,* a psychrometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and reporting both the raw data (*e.g.,* hourly average wet- and dry basis O_2 values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.

(3) Complete a minimum of one cycle of CO and oxygen (or CO_2) CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen (or CO_2) data concurrently. Collect at least four CO and oxygen (or CO_2) CEMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

* * * * *

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen (or corrected to an CO_2 percentage determined to be equivalent to 3 percent oxygen) from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19–19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A–7 for calculating the average CO concentration from the hourly values.

* * * * *

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (*e.g.,* bag leak detectors, ESP secondary power, and PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.

* * * * *

(iii) The PM CPMS must have a documented detection limit of 0.5 milligram per actual cubic meter, or less.

* * * * *

(g) * * *

(3) Calibrate the pH monitoring system in accordance with your monitoring plan and according to the

manufacturer's instructions. Clean the pH probe at least once each process operating day. Maintain on-site documentation that your calibration frequency is sufficient to maintain the specified accuracy of your device.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

* * * * *

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 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.

* * * * *

(2) For on-going quality assurance (QA), the SO_2 CEMS must meet either the applicable daily and quarterly requirements in Procedure 1 of appendix F of part 60 or the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

* * * * *

■ 12. Section 63.7530 is amended by:

■ a. Revising paragraph (a) and paragraph (b) introductory text.

■ b. Revising parameter ''Qi'' of Equation 7 in paragraph (b)(1)(iii), Equation 8 in paragraph (b)(2)(iii), and Equation 9 in paragraph (b)(3)(iii).

■ c. Revising parameter ''n'' of Equation 14 in paragraph (b)(4)(ii)(D).

■ d. Revising paragraph (b)(4)(ii)(F).

■ e. Redesignating paragraphs (b)(4)(iii) through (viii) as paragraphs (b)(4)(iv) through (ix) and adding new paragraph (b)(4)(iii).

■ f. Revising parameters ''Ci90'' and ''Qi'' of Equation 16 in paragraph (c)(3), parameters ''Hgi90'' and ''Qi'' of Equation 17 in paragraph (c)(4), and parameters ''TSMi90'' and ''Qi'' of Equation 18 in paragraph (c)(5).

■ g. Removing and reserving paragraph (d).

■ h. Revising paragraphs (e), (h), and (i)(3).

The revisions and additions read as follows:

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

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by § 63.7510(a)(2). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to § 63.7525.

(b) If you demonstrate compliance through performance stack testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to § 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in § 63.7510(a)(2). (Note that § 63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) * * *

(iii) * * *

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine during the initial compliance test. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

* * * * *

(2) * * *

(iii) * * *

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content during the initial compliance test. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

* * * * *

(3) * * *

(iii) * * *

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of TSM during the initial compliance test. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

* * * * *

(4) * * *

(ii) * * *

(D) * * *

n = is the number of valid hourly parameter values collected over the previous 30 operating days.

* * * * *

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (*e.g.* beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(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. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. 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.

(iv) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(v) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vii) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.

(viii) 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.

(ix) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO_2 CEMS is to install and operate the SO_2 according to the requirements in § 63.7525(m) establish a maximum SO_2 emission rate equal to the highest hourly average SO_2 measurement during the most recent three-run performance test for HCl.

(c) * * *

(3) * * *

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

* * * * *

(4) * * *

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

* * * * *

(5) * * *

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest TSM content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

* * * * *

(e) You must include with the Notification of Compliance Status a signed certification that either the energy assessment was completed according to Table 3 to this subpart, and that the assessment is an accurate depiction of your facility at the time of the assessment, or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.

* * * * *

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 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.

(i) * * *

(3) You establish a unit-specific maximum SO_2 operating limit by collecting the maximum hourly SO_2 emission rate on the SO_2 CEMS during the paired 3-run test for HCl. The maximum SO_2 operating limit is equal to the highest hourly average SO_2 concentration measured during the HCl performance test.

■ 13. Section 63.7533 is amended by revising paragraph (e) to read as follows:

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

* * * * *

(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 to this subpart at all times the affected unit is subject to numeric emission limits, following the compliance date specified in § 63.7495.

* * * * *

■ 14. Section 63.7535 is amended by revising paragraphs (c) and (d) to read as follows:

§ 63.7535 Is there a minimum amount of monitoring data I must obtain?

* * * * *

(c) You may not use data recorded during periods of startup and shutdown, monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods of startup and shutdown, when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your semi-annual report.

■ 15. Section 63.7540 is amended by:
■ a. Revising paragraph (a)(2).
■ b. Revising paragraphs (a)(3) introductory text and (a)(3)(iii).
■ c. Revising paragraphs (a)(5) introductory text and (a)(5)(iii).
■ d. Revising paragraph (a)(8)(ii).
■ e. Revising paragraph (a)(10) introductory text.
■ f. Revising paragraph (a)(10)(i).
■ g. Revising paragraph (a)(10)(vi) introductory text.
■ h. Revising paragraphs (a)(12).
■ i. Revising paragraphs (a)(14)(i) and (a)(15)(i).
■ j. Revising paragraphs (a)(17) introductory text and (a)(17)(iii).
■ k. Revising paragraph (a)(18)(i).
■ l. Revising paragraph (a)(19)(iii).
■ m. Revising paragraph (d).

The revisions read as follows:

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

(a) * * *

(2) As specified in § 63.7555(d), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Equal to or lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Equal to or lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 16 of § 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

* * * * *

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 16 of § 63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

* * * * *

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 17 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

* * * * *

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 17 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

* * * * *

(8) * * *

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 13 to this subpart at all times the affected unit is subject to numeric emission limits.

* * * * *

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. You must conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. This frequency does not apply to limited-use boilers and process heaters, as defined in § 63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

* * * * *

(vi) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

* * * * *

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up.

* * * * *

(14) * * *

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in § 63.7545(e)(2)(iii) for mercury CEMS or it must be 720 hours if you specified a 720 hour basis in § 63.7545(e)(2)(iii) for mercury CEMS. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

* * * * *

(15) * * *

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in § 63.7545(e)(2)(iii) for HCl CEMS or it must be 720 hours if you specified a 720 hour basis in § 63.7545(e)(2)(iii) for HCl CEMS. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

* * * * *

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 18 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

* * * * *

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 18 of § 63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

* * * * *

(18) * * *

(i) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis.

* * * * *

(19) * * *

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (v) of this section.

* * * * *

(d) For startup and shutdown, you must meet the work practice standards according to items 5 and 6 of Table 3 of this subpart.

■ 16. Section 63.7545 is amended by revising paragraphs (e) introductory text, (e)(8)(i), adding paragraph (e)(2)(iii), and revising paragraph (h) introductory text to read as follows:

§ 63.7545 What notifications must I submit and when?

* * * * *

(e) If you are required to conduct an initial compliance demonstration as specified in § 63.7530, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8) of this section, as applicable. If you are not required to conduct an initial compliance demonstration as specified in § 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8) of this section and must be submitted within 60 days of the compliance date specified at § 63.7495(b).

* * * * *

(2) * * *

(iii) Identification of whether you are complying the arithmetic mean of all valid hours of data from the previous 30 operating days or of the previous 720 hours. This identification shall be specified separately for each operating parameter.

* * * * *

(8) * * *

(i) ''This facility completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in § 63.7540(a)(10)(i) through (vi).''

* * * * *

(h) If you have switched fuels or made a physical change to the boiler or process heater and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

* * * * *

■ 17. Section 63.7550 is amended by revising paragraphs (b), (c)(1) through (4), (c)(5)(viii) and (xvi), adding paragraph (c)(5)(xviii), and revising paragraph (d) introductory text, (d)(1), and (h) to read as follows:

§ 63.7550 What reports must I submit and when?

* * * * *

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct subsequent annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or Table 4 operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first semi-annual compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in § 63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in § 63.7495. If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in § 63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for your source in § 63.7495.

(2) The first semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in § 63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this

chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) * * *

(1) If the facility is subject to the requirements of a tune up you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii) of this section, (xiv) and (xvii) of this section, and paragraph (c)(5)(iv) of this section for limited-use boiler or process heater.

(2) If you are complying with the fuel analysis you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (vi), (x), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(3) If you are complying with the applicable emissions limit with performance testing you must submit a compliance report with the information in (c)(5)(i) through (iii), (vi), (vii), (viii), (ix), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(4) If you are complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (iii), (v), (vi), (xi) through (xiii), (xv) through (xviii), and paragraph (e) of this section.

(5) * * *

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of § 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 16 of § 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of § 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 17 of § 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of § 63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 18 of § 63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

* * * * *

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values for CEMS (CO, HCl, SO_2, and mercury), 10 day rolling average values for CO CEMS when the limit is expressed as a 10 day instead of 30 day rolling average, and the PM CPMS data.

* * * * *

(xviii) For each instance of startup or shutdown include the information required to be monitored, collected, or recorded according to the requirements of § 63.7555(d).

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, or from the work practice standards for periods if startup and shutdown, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.

* * * * *

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (as defined in § 63.2) required by this subpart, you must submit the results of the performance tests, including any fuel analyses, following the procedure specified in either paragraph (h)(1)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*http://www.epa.gov/ttn/chief/ert/index.html*), you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through use of the EPA's ERT or an electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in § 63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation (as defined in 63.2), you must submit the results of the performance evaluation following the procedure specified in either paragraph (h)(2)(i) or (ii) of this section.

(i) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT

Web site. If you claim that some of the performance evaluation information being transmitted is CBI, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in § 63.13.

(3) You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 63.13. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.

■ 18. Section 63.7555 is amended by:
■ a. Adding paragraph (a)(3).
■ b. Removing paragraph (d)(3).
■ c. Redesignating paragraphs (d)(4) through (11) as paragraphs (d)(3) through (10).
■ d. Revising newly designated paragraphs (d)(3), (d)(4), and (d)(8).
■ e. Adding new paragraph (d)(11) and paragraphs (d)(12) and (d)(13).
■ f. Removing paragraphs (i) and (j).

The additions and revisions read as follows:

§ 63.7555 What records must I keep?

(a) * * *

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

* * * * *

(d) * * *

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 16 of § 63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(4) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of § 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 17 of § 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

* * * * *

(8) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of § 63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 18 of § 63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

* * * * *

(11) For each startup period, for units selecting paragraph (2) of the definition of ''startup'' in § 63.7575 you must maintain records of the time that clean fuel combustion begins; the time when you start feeding fuels that are not clean fuels; the time when useful thermal energy is first supplied; and the time when the PM controls are engaged.

(12) If you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.7575, for each startup period, you must maintain records of the hourly steam temperature, hourly steam pressure, hourly steam flow, hourly flue gas temperature, and all hourly average CMS data (*e.g.,* CEMS, PM CPMS, COMS, ESP total secondary electric power input, scrubber pressure drop, scrubber liquid flow rate) collected during each startup period to confirm that the control devices are engaged. In addition, if compliance with the PM emission limit is demonstrated using a PM control device, you must maintain records as specified in paragraphs (d)(12)(i) through (iii) of this section.

(i) For a boiler or process heater with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(ii) For a boiler or process heater with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(iii) For a boiler or process heater with a wet scrubber needed for filterable PM control, record the scrubber's liquid flow rate and the pressure drop during each hour of startup.

(13) If you choose to use paragraph (2) of the definition of ''startup'' in § 63.7575 and you find that you are unable to safely engage and operate your PM control(s) within 1 hour of first firing of non-clean fuels, you may choose to rely on paragraph (1) of

definition of ''startup'' in § 63.7575 or you may submit to the delegated permitting authority a request for a variance with the PM controls requirement, as described below.

(i) The request shall provide evidence of a documented manufacturer-identified safety issue.

(ii) The request shall provide information to document that the PM control device is adequately designed and sized to meet the applicable PM emission limit.

(iii) In addition, the request shall contain documentation that:

(A) The unit is using clean fuels to the maximum extent possible to bring the unit and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel;

(B) The unit has explicitly followed the manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) Identifies with specificity the details of the manufacturer's statement of concern.

(iv) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.

* * * * *

■ 19. Section 63.7570 is amended by revising paragraph (b) to read as follows:

§ 63.7570 Who implements and enforces this subpart?

* * * * *

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission limits and work practice standards in § 63.7500(a) and (b) under § 63.6(g), except as specified in § 63.7555(d)(13).

(2) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, and alternative analytical methods requested under § 63.7521(b)(2).

(3) Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90, and approval of alternative operating parameters under §§ 63.7500(a)(2) and 63.7522(g)(2).

(4) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

■ 20. Section 63.7575 is amended by:

■ a. Revising the definition for ''30-day rolling average.''

■ b. Removing the definition for ''Affirmative defense.''

■ c. Adding in alphabetical order a definition for ''Clean dry biomass.''

■ d. Revising the definition for ''Energy assessment.''

■ e. Adding in alphabetical order a definition for ''Fossil fuel.''

■ f. Revising the definitions for ''Hybrid suspension grate boiler,'' ''Limited-use boiler or process heater,'' ''Liquid fuel,'' ''Load fraction,'' ''Minimum sorbent injection rate,'' ''Operating day,'' and ''Oxygen trim system.''

■ g. Adding in alphabetical order a definition for ''Rolling average''.

■ h. Revising the definitions for ''Shutdown,'' ''Startup,'' ''Steam output,'' and ''Temporary boiler.''

■ i. Adding in alphabetical order a definition for ''Useful thermal energy.''

The revisions and additions read as follows:

§ 63.7575 What definitions apply to this subpart?

* * * * *

30-day rolling average means the arithmetic mean of the previous 720 hours of valid CO CEMS data. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent. For parameters other than CO, 30-day rolling average means either the arithmetic mean of all valid hours of data from 30 successive operating days or the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating.

* * * * *

Clean dry biomass means any biomass-based solid fuel that have not been painted, pigment-stained, or pressure treated, does not contain contaminants at concentrations not normally associated with virgin biomass materials and has a moisture content of less than 20 percent and is not a solid waste.

* * * * *

Energy assessment means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of less than 0.3 trillion Btu (TBtu) per year will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (*e.g.,* steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment.

(2) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of 0.3 to 1.0 TBtu/year will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 33 percent of the energy (*e.g.,* steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour on-site energy assessment.

(3) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity greater than 1.0 TBtu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 20 percent of the energy (*e.g.,* steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy production in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (*e.g.,* product X manufacturing area; product Y drying area; Building Z).

* * * * *

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

* * * * *

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis as demonstrated by monthly fuel analysis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

* * * * *

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable annual capacity factor of no more than 10 percent.

Liquid fuel includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, and vegetable oil.

Load fraction means the actual heat input of a boiler or process heater divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (*e.g.,* for 50 percent load the load fraction is 0.5). For boilers and process heaters that co-fire natural gas or refinery gas with a solid or liquid fuel, the load fraction is determined by the actual heat input of the solid or liquid fuel divided by heat input of the solid or liquid fuel fired during the performance test (*e.g.,* if the performance test was conducted at 100 percent solid fuel firing, for 100 percent load firing 50 percent solid fuel and 50 percent natural gas the load fraction is 0.5).

* * * * *

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion not using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

* * * * *

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period. For calculating rolling average emissions, an operating day does not include the hours of operation during startup or shutdown.

* * * * *

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device over its operating load range. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller or draft controller.

* * * * *

Rolling average means the average of all data collected during the applicable averaging period. For demonstration of compliance with a CO CEMS-based emission limit based on CO concentration a 30-day (10-day) rolling average is comprised of the average of all the hourly average concentrations over the previous 720 (240) operating hours calculated each operating day. To demonstrate compliance on a 30-day rolling average basis for parameters other than CO, you must indicate the basis of the 30-day rolling average period you are using for compliance, as discussed in § 63.7545(e)(2)(iii). If you indicate the 30 operating day basis, you must calculate a new average value each operating day and shall include the measured hourly values for the preceding 30 operating days. If you select the 720 operating hours basis, you must average of all the hourly average concentrations over the previous 720 operating hours calculated each operating day.

Shutdown means the period in which cessation of operation of a boiler or process heater is initiated for any purpose. Shutdown begins when the boiler or process heater no longer supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes and/or generates electricity or when no fuel is being fed to the boiler or process heater, whichever is earlier. Shutdown ends when the boiler or process heater no longer supplies useful thermal energy (such as steam or heat) for heating, cooling, or process purposes and/or generates electricity, and no fuel is being combusted in the boiler or process heater.

* * * * *

Startup means:

(1) Either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the useful thermal energy from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose, or

(2) The period in which operation of a boiler or process heater is initiated for any purpose. Startup begins with either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy (such as steam or heat) for heating, cooling or process purposes, or producing electricity, or the firing of fuel in a boiler or process heater for any purpose after a shutdown event. Startup ends four hours after when the boiler or process heater supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes, or generates electricity, whichever is earlier.

Steam output means:

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(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 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 heaters, 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 heater.

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

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

* * * * *

Temporary boiler means any gaseous or liquid fuel boiler or process heater that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler or process heater is not a temporary boiler or process heater if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or process heater or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler or process heater that replaces a temporary boiler or process heater at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, process heat, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

* * * * *

Useful thermal energy means energy (*i.e.,* steam, hot water, or process heat) that meets the minimum operating temperature, flow, and/or pressure required by any energy use system that uses energy provided by the affected boiler or process heater.

* * * * *

■ 21. Table 1 to subpart DDDDD of part 63 is amended by:

■ a. Revising rows ''3.a'', ''4.a'', ''5.a'', ''6.a'', ''7.a'', ''9.a'', ''10.a'', ''11.a'', and ''13.a''.

■ b. Revising footnote ''c''; and

■ c. Adding footnote ''d''.

The revisions and addition read as follows:

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

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS

[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 . . .
*	*	*	*	*
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; 3-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; 3-run average.	1 hr minimum sampling time.

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS—Continued

[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 . . .
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; 3-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; 3-run average.	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 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).	5.8E–01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average.	1 hr minimum sampling time.
* * *	* * *	* * *	* * *	* * *
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, 3-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; 3-run average.	1 hr minimum sampling time.
* * *	* * *	* * *	* * *	* * *
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, 3-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; 3-run average.	1 hr minimum sampling time.
* * *	* * *	* * *	* * *	* * *
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; 3-run average.	1 hr minimum sampling time.
* * *	* * *	* * *	* * *	* * *
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, 3-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; 3-run average.	1 hr minimum sampling time.

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS—Continued

[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 . . .
* * * * * * *				

* * * * * * *

[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, 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 carbon dioxide as a diluent correction in place of oxygen at 3%. 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% 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.

■ 22. Table 2 to subpart DDDDD of part 63 is amended by revising the rows ''3.a'', ''4.a'', ''5.a'', ''6.a'', ''7.a'', ''9.a'', ''10.a'', ''11.a'', ''13.a'', ''14.b'', and ''16.b'' and adding footnote ''c'' to read as follows:

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

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS

[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 . . .
* * * * * * *				
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, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average).	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
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, 3-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; 3-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,[c] 30-day rolling average).	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-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,[c] 30-day rolling average).	1.3E–01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average.	1 hr minimum sampling time.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS—Continued

[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 . . .
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, 3-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; 3-run average.	1 hr minimum sampling time.
*	* *	*	* *	*
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, 3-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; 3-run average.	1 hr minimum sampling time.
*	* *	*	* *	*
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, 3-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; 3-run average.	1 hr minimum sampling time.
*	* *	*	* *	*
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, 3-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; 3-run average.	1 hr minimum sampling time.
*	* *	*	* *	*
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, 3-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; 3-run average.	1 hr minimum sampling time.
*	* *	*	* *	*
14. Units designed to burn liquid fuel.	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.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS—Continued

[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 . . .
* * * * * * *				
16. Units designed to burn light liquid fuel.	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.
* * * * * * *				

* * * * * * *

[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 carbon dioxide as a diluent correction in place of oxygen at 3%. 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% 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.

■ 23. Table 3 to subpart DDDDD of part 63 is amended by revising the entries for ''4,'' ''5,'' and ''6'' and adding footnote ''a'' to read as follows:

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

TABLE 3 TO SUBPART DDDDD OF PART 63—WORK PRACTICE STANDARDS

If your unit is . . .	You must meet the following . . .
* * * * * * *	
4. An existing boiler or process heater located at a major source facility, not including limited use units.	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least one year between January 1, 2008 and the compliance date specified in § 63.7495 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in § 63.7575: a. A visual inspection of the boiler or process heater system. b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints. c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator. d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage. e. A review of the facility's energy management program and provide recommendations for improvements consistent with the definition of energy management program, if identified. f. A list of cost-effective energy conservation measures that are within the facility's control. g. A list of the energy savings potential of the energy conservation measures identified. h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

TABLE 3 TO SUBPART DDDDD OF PART 63—WORK PRACTICE STANDARDS—Continued

If your unit is . . .	You must meet the following . . .
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup.	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 13 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.

[a] As specified in § 63.7555(d)(13), the source may request an alternative timeframe with the PM controls requirement to the permitting authority (state, local, or tribal agency) that has been delegated authority for this subpart by EPA. The source must provide evidence that (1) it is unable to safely engage and operate the PM control(s) to meet the "fuel firing + 1 hour" requirement and (2) the PM control device is appropriately designed and sized to meet the filterable PM emission limit. It is acknowledged that there may be another control device that has been installed other than ESP that provides additional PM control (*e.g.*, scrubber).

■ 24. Table 4 to subpart DDDDD of part 63 is revised to read as follows:

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

TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
1. Wet PM scrubber control on a boiler or process heater not using a PM CPMS.	Maintain the 30-day rolling average pressure drop and the 30-day rolling average liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the performance test demonstrating compliance with the PM emission limitation according to § 63.7530(b) and Table 7 to this subpart.

TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS—Continued

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
2. Wet acid gas (HCl) scrubber[a] control on a boiler or process heater not using a HCl CEMS.	Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the performance test demonstrating compliance with the HCl emission limitation according to § 63.7530(b) and Table 7 to this subpart.
3. Fabric filter control on a boiler or process heater not using a PM CPMS.	a. Maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average); or
	b. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period.
4. Electrostatic precipitator control on a boiler or process heater not using a PM CPMS.	a. This option is for boilers and process heaters that operate dry control systems (*i.e.*, an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).
	b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (*i.e.*, dry ESP). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(b) and Table 7 to this subpart.
5. Dry scrubber or carbon injection control on a boiler or process heater not using a mercury CEMS.	Maintain the minimum sorbent or carbon injection rate as defined in § 63.7575 of this subpart.
6. Any other add-on air pollution control type on a boiler or process heater not using a PM CPMS.	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).
7. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the 30-day rolling average operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test.
8. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2 analyzer system as specified in § 63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a).
9. SO_2 CEMS	For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO_2 CEMS, maintain the 30-day rolling average SO_2 emission rate at or below the highest hourly average SO_2 concentration measured during the HCl performance test, as specified in Table 8.

[a] A wet acid gas scrubber is a control device that removes acid gases by contacting the combustion gas with an alkaline slurry or solution. Alkaline reagents include, but not limited to, lime, limestone and sodium.

■ 25. Table 5 to subpart DDDDD of part 63 is amended by revising the heading to the third column and adding footnote ''a'' to read as follows:

As stated in § 63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

TABLE 5 TO SUBPART DDDDD OF PART 63—PERFORMANCE TESTING REQUIREMENTS

To conduct a performance test for the following pollutant . . .	You must . . .	Using, as appropriate . . .
*	* *	* *

[a] Incorporated by reference, see § 63.14.

■ 26. Table 6 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

TABLE 6 TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192,[a] or ASTM D7430,[a] or ASTM D6883,[a] or ASTM D2234/D2234M [a] (for coal) or ASTM D6323 [a] (for solid), or ASTM D4177 [a] (for liquid), or ASTM D4057 [a] (for liquid), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples.	EPA SW–846–3050B [a] (for solid samples), ASTM D2013/D2013M [a] (for coal), ASTM D5198 [a] (for biomass), or EPA 3050 [a] (for solid fuel), or EPA 821–R–01–013 [a] (for liquid or solid), or equivalent.
	d. Determine heat content of the fuel type.	ASTM D5865 [a] (for coal) or ASTM E711 [a] (for biomass), or ASTM D5864 [a] for liquids and other solids, or ASTM D240 [a] or equivalent.
	e. Determine moisture content of the fuel type.	ASTM D3173,[a] ASTM E871,[a] or ASTM D5864,[a] or ASTM D240, or ASTM D95 [a] (for liquid fuels), or ASTM D4006 [a] (for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample.	ASTM D6722 [a] (for coal), EPA SW–846–7471B [a] or EPA 1631 or EPA 1631E (for solid samples), or EPA SW–846–7470A [a] (for liquid samples), or EPA 821–R–01–013 (for liquid or solid), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content.	For fuel mixtures use Equation 8 in § 63.7530.
2. HCl	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192,[a] or ASTM D7430,[a] or ASTM D6883,[a] or ASTM D2234/D2234M [a] (for coal) or ASTM D6323 [a] (for coal or biomass), ASTM D4177 [a] (for liquid fuels) or ASTM D4057 [a] (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples.	EPA SW–846–3050B [a] (for solid samples), ASTM D2013/D2013M [a] (for coal), or ASTM D5198 [a] (for biomass), or EPA 3050 [a] or equivalent.
	d. Determine heat content of the fuel type.	ASTM D5865 [a] (for coal) or ASTM E711 [a] (for biomass), ASTM D5864, ASTM D240 [a] or equivalent.
	e. Determine moisture content of the fuel type.	ASTM D3173 [a] or ASTM E871,[a] or D5864,[a] or ASTM D240,[a] or ASTM D95 [a] (for liquid fuels), or ASTM D4006 [a] (for liquid fuels), or equivalent.
	f. Measure chlorine concentration in fuel sample.	EPA SW–846–9250,[a] ASTM D6721,[a] ASTM D4208 [a] (for coal), or EPA SW–846–5050 [a] or ASTM E776 [a] (for solid fuel), or EPA SW–846–9056 [a] or SW–846–9076 [a] (for solids or liquids) or equivalent.
	g. Convert concentrations into units of pounds of HCl per MMBtu of heat content.	For fuel mixtures use Equation 7 in § 63.7530 and convert from chlorine to HCl by multiplying by 1.028.
3. Mercury Fuel Specification for other gas 1 fuels.	a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter, or	Method 30B (M30B) at 40 CFR part 60, appendix A–8 of this chapter or ASTM D5954,[a] ASTM D6350,[a] ISO 6978–1:2003(E),[a] or ISO 6978–2:2003(E),[a] or EPA–1631 [a] or equivalent.
	b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater.	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A–8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784 [a] or equivalent.
4. TSM	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192,[a] or ASTM D7430,[a] or ASTM D6883,[a] or ASTM D2234/D2234M [a] (for coal) or ASTM D6323 [a] (for coal or biomass), or ASTM D4177,[a] (for liquid fuels) or ASTM D4057 [a] (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples.	EPA SW–846–3050B [a] (for solid samples), ASTM D2013/D2013M [a] (for coal), ASTM D5198 [a] or TAPPI T266 [a] (for biomass), or EPA 3050 [a] or equivalent.
	d. Determine heat content of the fuel type.	ASTM D5865 [a] (for coal) or ASTM E711 [a] (for biomass), or ASTM D5864 [a] for liquids and other solids, or ASTM D240 [a] or equivalent.
	e. Determine moisture content of the fuel type.	ASTM D3173 [a] or ASTM E871,[a] or D5864, or ASTM D240,[a] or ASTM D95 [a] (for liquid fuels), or ASTM D4006 [a] (for liquid fuels), or ASTM D4177 [a] (for liquid fuels) or ASTM D4057 [a] (for liquid fuels), or equivalent.
	f. Measure TSM concentration in fuel sample.	ASTM D3683,[a] or ASTM D4606,[a] or ASTM D6357 [a] or EPA 200.8 [a] or EPA SW–846–6020,[a] or EPA SW–846–6020A,[a] or EPA SW–846–6010C,[a] EPA 7060 [a] or EPA 7060A [a] (for arsenic only), or EPA SW–846–7740 [a] (for selenium only).
	g. Convert concentrations into units of pounds of TSM per MMBtu of heat content.	For fuel mixtures use Equation 9 in § 63.7530.

[a] Incorporated by reference, see § 63.14.

■ 27. Table 7 to subpart DDDDD of part 63 is revised to read as follows:

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

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS [a b]

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. PM, TSM, or mercury	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to § 63.7530(b).	(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM, TSM, or mercury performance test.	(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests. (b) Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers).	i. Establish a site-specific minimum total secondary electric power input according to § 63.7530(b).	(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test.	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests. (b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	c. Opacity	i. Establish a site-specific maximum opacity level.	(1) Data from the opacity monitoring system during the PM performance test.	(a) You must collect opacity readings every 15 minutes during the entire period of the performance tests. (b) Determine the average hourly opacity reading for each performance test run by computing the hourly averages using all of the 15-minute readings taken during each performance test run. (c) Determine the highest hourly average opacity reading measured during the test run demonstrating compliance with the PM (or TSM) emission limitation.
2. HCl	a. Wet scrubber operating parameters.	i. Establish site-specific minimum effluent pH and flow rate operating limits according to § 63.7530(b).	(1) Data from the pH and liquid flow-rate monitors and the HCl performance test.	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS [a b]—Continued

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
	b. Dry scrubber operating parameters.	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent.	(1) Data from the sorbent injection rate monitors and HCl or mercury performance test.	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction, as defined in § 63.7575, to determine the required injection rate.
	c. Alternative Maximum SO_2 emission rate.	i. Establish a site-specific maximum SO_2 emission rate operating limit according to § 63.7530(b).	(1) Data from SO_2 CEMS and the HCl performance test.	(a) You must collect the SO_2 emissions data according to § 63.7525(m) during the most recent HCl performance tests. (b) The maximum SO_2 emission rate is equal to the highest hourly average SO_2 emission rate measured during the most recent HCl performance tests.
3. Mercury	a. Activated carbon injection.	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b).	(1) Data from the activated carbon rate monitors and mercury performance test.	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction, as defined in § 63.7575, to determine the required injection rate.

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS [a] [b]—Continued

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
4. Carbon monoxide for which compliance is demonstrated by a performance test.	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7530(b).	(1) Data from the oxygen analyzer system specified in § 63.7525(a).	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test.	a. Boiler or process heater operating load.	i. Establish a unit specific limit for maximum operating load according to § 63.7520(c).	(1) Data from the operating load monitors or from steam generation monitors.	(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test. (b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the highest hourly average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

[a] Operating limits must be confirmed or reestablished during performance tests.

[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.

■ 28. Table 8 to subpart DDDDD of part 63 is amended by:

■ a. Revising the entries for rows ''1.c'' and ''3.''

■ b. Adding row ''8.d''.

■ c. Revising the entries for rows''9.a,'' ''9.c,'' ''10,'' and ''11.c.''

The revisions and addition read as follows:

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

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
* *	* * * * *
1. Opacity	c. Maintaining daily block average opacity to less than or equal to 10 percent or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation.
* *	* * * * *
3. Fabric Filter Bag Leak Detection Operation.	Installing and operating a bag leak detection system according to § 63.7525 and operating the fabric filter such that the requirements in § 63.7540(a)(7) are met.
* *	* * * * *
8. Emission limits using fuel analysis.	d. Calculate the HCl, mercury, and/or TSM emission rate from the boiler or process heater in units of lb/MMBtu using Equation 15 and Equations 17, 18, and/or 19 in § 63.7530.

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE—Continued

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen analyzer system according to § 63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a)(7).
* *	* * * * *
11. SO_2 emissions using SO_2 CEMS.	c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the CO performance test.
10. Boiler or process heater operating load.	a. Collecting operating load data or steam generation data every 15 minutes.
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test according to § 63.7520(c).
* *	* * * * *
	c. Maintaining the 30-day rolling average SO_2 CEMS emission rate to a level at or below the highest hourly SO_2 rate measured during the HCl performance test according to § 63.7530.

■ 29. Table 9 to subpart DDDDD of part 63 is amended by revising the entries for ''1.b'' and ''1.c'' to read as follows:

As stated in § 63.7550, you must comply with the following requirements for reports:

TABLE 9 TO SUBPART DDDDD OF PART 63—REPORTING REQUIREMENTS

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards for periods of startup and shutdown in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and	
	c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard for periods of startup and shutdown, during the reporting period, the report must contain the information in § 63.7550(d); and	
* *	* * *	* *

■ 30. Table 10 to subpart DDDDD of part 63 is amended by revising the rows associated with ''§ 63.6(g)'' and ''§ 63.6(h)(2) to (h)(9)'' to read as follows:

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

TABLE 10 TO SUBPART DDDDD OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD

Citation	Subject	Applies to subpart DDDDD
* * *	* *	* *
§ 63.6(g)	Use of alternative standards.	Yes, except § 63.7555(d)(13) specifies the procedure for application and approval of an alternative timeframe with the PM controls requirement in the startup work practice (2).
* * *	* *	* *
§ 63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards.	No. Subpart DDDDD specifies opacity as an operating limit not an emission standard.
* * *	* *	* *

■ 31. Table 11 to subpart DDDDD of part 63 is revised to read as follows:

TABLE 11 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011

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 periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	0.022 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis.	a. Mercury	8.0E–07 [a] lb per MMBtu of heat input.	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.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis.	a. Mercury	2.0E–06 lb per MMBtu of heat input.	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.
4. Units design 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).	Collect a minimum of 3 dscm per run.
5. 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,[c] 30-day rolling average).	1 hr minimum sampling time.
6. Stokers 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,[c] 10-day rolling average).	1 hr minimum sampling time.

TABLE 11 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

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 periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
7. 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,[c] 30-day rolling average).	1 hr minimum sampling time.
8. 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,[c] 30-day rolling average).	1 hr minimum sampling time.
9. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 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,[c] 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
10. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	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).	Collect a minimum of 2 dscm per run.
11. 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, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling 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).	Collect a minimum of 3 dscm per run.
12. 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, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling 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).	Collect a minimum of 2 dscm per run.

TABLE 11 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

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 periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
13. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,010 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,[c] 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	8.0E–03 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
14. 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, 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
15. 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, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling 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).	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel.	a. HCl	4.4E–04 lb per MMBtu of heat input.	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.	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.
17. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-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).	Collect a minimum of 3 dscm per run.
18. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E–03[a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
19. 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.	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).	Collect a minimum of 4 dscm per run.

TABLE 11 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

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 periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
20. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input.	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.	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).	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 provision 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 carbon dioxide as a diluent correction in place of oxygen at 3%. 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% 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.

■ 32. Table 12 to subpart DDDDD of part 63 is revised to read as follows:

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 20, 2011, AND BEFORE DECEMBER 23, 2011

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 periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	3.5E–06 [a] lb per MMBtu of heat input	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).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	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,[c] 30-day rolling average).	1 hr minimum sampling time.
4. Stokers 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,[c] 10-day rolling 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,[c] 30-day rolling average).	1 hr minimum sampling time.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 20, 2011, AND BEFORE DECEMBER 23, 2011—Continued

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 periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
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,[c] 30-day rolling average).	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 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,[c] 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	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, 3-run average.	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).	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	260 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,[c] 30-day rolling 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).	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, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling 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).	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	470 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,[c] 10-day rolling 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 per MMBtu of heat input).	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, 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling 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).	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	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	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, 3-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).	Collect a minimum of 2 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, 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–03[a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 20, 2011, AND BEFORE DECEMBER 23, 2011—Continued

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 periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
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.	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).	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, 3-run average.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input	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	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).	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 provision 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 carbon dioxide as a diluent correction in place of oxygen at 3%. 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% 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.

■ 33. Table 13 to subpart DDDDD of part 63 is amended by:

■ a. Revising the heading of the table.

■ b. Revising rows "2.a", "3.a", "4.a", "5.a", "6.a", "8.a", "9.a", "10.a", "12.a", "14.a", "15.a", and "16.a".

■ c. Adding footnote "c".

The revisions and addition read as follows:

TABLE 13 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER DECEMBER 23, 2011, AND BEFORE APRIL 1, 2013

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 periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
*	* *	* * *	*
2. 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,[c] 30-day rolling average).	1 hr minimum sampling time.
*	* *	* * *	*
3. Stokers 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,[c] 10-day rolling average).	1 hr minimum sampling time.
*	* *	* * *	*
4. 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,[c] 30-day rolling average).	1 hr minimum sampling time.
*	* *	* * *	*
5. 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,[c] 30-day rolling average).	1 hr minimum sampling time.

TABLE 13 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER DECEMBER 23, 2011, AND BEFORE APRIL 1, 2013—Continued

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 periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
* * * * * * *			
6. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average).	1 hr minimum sampling time.
* * * * * * *			
8. 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, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average).	1 hr minimum sampling time.
* * * * * * *			
9. 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, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average).	1 hr minimum sampling time.
* * * * * * *			
10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	810 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,[c] 10-day rolling average).	1 hr minimum sampling time.
* * * * * * *			
12. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 30-day rolling average).	1 hr minimum sampling time.
* * * * * * *			
14. Units designed to burn heavy liquid fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 10-day rolling average).	1 hr minimum sampling time.
* * * * * * *			
15. Units designed to burn light liquid fuel.	a. CO (or CEMS)	130[a] ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen,[c] 1-day block average).	1 hr minimum sampling time.
* * * * * * *			
16. 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; or (91 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-hour rolling average).	1 hr minimum sampling time.
* * * * * * *			

* * * * * * *

[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 carbon dioxide as a diluent correction in place of oxygen at 3%. 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% 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.

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