FEDERAL REGISTER

Vol. 78 Thursday,
No. 21 January 31, 2013

Part V

Environmental Protection Agency

40 CFR Part 63
National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2002–0058; FRL–9676–8]

RIN 2060–AR13

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: In this action the EPA is taking final action on its reconsideration of certain issues in the emission standards for the control of hazardous air pollutants from new and existing industrial, commercial, and institutional boilers and process heaters at major sources of hazardous air pollutants, which were issued under section 112 of the Clean Air Act. As part of this action, the EPA is making technical corrections to the final rule to clarify definitions, references, applicability and compliance issues raised by petitioners and other stakeholders affected by this rule. On March 21, 2011, the EPA promulgated national emission standards for this source category. On that same day, the EPA also published a notice announcing its intent to reconsider certain provisions of the final rule. Following these actions, the Administrator received several petitions for reconsideration. After consideration of the petitions received, on December 23, 2011, the EPA proposed revisions to certain provisions of the March 21, 2011, final rule, and requested public comment on several provisions of the final rule. The EPA is now taking final action on the proposed reconsideration.

DATES: The May 18, 2011 (76 FR28661), delay of the effective date revising subpart DDDDD at 76 FR 15451 (March 21, 2011) is lifted January 31, 2013. The amendments in this rule to 40 CFR part 63, subpart DDDDD are effective as of April 1, 2013.

ADDRESSES: The EPA established a single docket under Docket ID No. EPA–HQ–OAR–2002–0058 for this action. All documents in the docket are listed on the *http://www.regulations.gov* Web site. 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, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue NW., Washington, DC 20004. This Docket Facility 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 Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Jim Eddinger, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–5426; Fax number (919) 541–5450; Email address: *eddinger.jim@epa.gov*.

SUPPLEMENTARY INFORMATION:

Executive Summary

Purpose of This Regulatory Action

The EPA is taking final action on its proposed reconsideration of certain provisions of its March 21, 2011, final rule that established standards for new and existing industrial, commercial, and institutional boilers and process heaters at major sources of hazardous air pollutants. Section 112(d) of the CAA requires the EPA to regulate HAP from major stationary sources based on the performance of MACT. Section 112(h) of the CAA allows the EPA to establish work practice standards in lieu of numerical emission limits only in cases where the agency determines that it is not feasible to prescribe or enforce an emission standard, including circumstances in which the agency determines that the application of measurement methodology is not practicable due to technological and economic limitations. The EPA is revising certain MACT standards established in March 2011 for boilers and process heaters, including standards for CO—as a surrogate for organic HAP; HCl—as a surrogate for acid gas HAP; Hg; TSM or filterable PM—as a surrogate for non-Hg metallic HAP; and dioxin/furan.

This final rule amends certain provisions of the final rule issued by the EPA on March 21, 2011. The EPA delayed the effective date of the 2011 rule in a May 18, 2011, notice, but that delay notice was vacated by the U.S. District Court for the District of Columbia on January 9, 2012, and the March 2011 final rule was, therefore, in effect until publication of this action.

Summary of Major Reconsideration Provisions

In general, this final rule requires facilities classified as major sources of HAP with affected boilers or process heaters to reduce emissions of harmful toxic air emissions from these combustion sources. This will improve air quality and protect public health in communities where these facilities are located.

Recognizing the diversity of this source category and the multiple sectors of the economy this final rule effects, the EPA is revising certain subcategories for boilers and process heaters in this action that were established in the March 2011 final rule, based on the design of the combustion equipment. These revisions result in 19 subcategories for the boilers and process heaters source category. Numerical emission limits are established for most of the subcategories for five pollutants, CO, HCl, Hg, and PM or TSM. The review of existing data and consideration of new data have resulted in changes to some of the emission limits contained in the March 2011 final rule. Overall, for both new and existing affected units, about 30 percent of the emission limits are more stringent, half are less stringent, and 20 percent unchanged as compared to the March 2011 final rule. Also, based on its review and analysis of new data submissions, the EPA is establishing an alternative emission standard for CO, based on CEMS data for several subcategories with CO CEMS data available. This alternative standard is based on a 30-day rolling average for subcategories for which sufficient CEMS data were available for more than a 30-day period, or a 10-day rolling average for subcategories for which CEMS data were available for less than a 30-day period, and provides additional compliance flexibility to sources. All of the subcategories are subject to periodic tune-up work practices for dioxin/furan emissions.

The compliance dates for the rule are January 31, 2016, for existing sources and, January 31, 2013, or upon startup, whichever is later, for new sources. New sources are defined as sources that began operation on or after June 4, 2010.

Costs and Benefits

The final rule affects 1,700 existing major source facilities with an estimated 14,136 boilers and process heaters and the EPA projects an additional 1,844 new boilers and process heaters to be subject to this final rule over the next 3 years. This final rule affects multiple sectors of the economy including small entities. Table 1 summarizes the costs and benefits associated with this final rule. A more detailed discussion of the costs and benefits of this final rule is provided in section VI of this preamble.

TABLE 1—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL BOILER MACT RECONSIDERATION IN 2015

[Millions of 2008$] [1]

	3 percent discount rate	7 percent discount rate
Total Monetized Benefits [2]	$27,000 to $67,000	$25,000 to $61,000.
Total Social Costs [3]	$1,400 to $1,600	$1,400 to $1,600.
Net Benefits	$26,000 to $65,000	$23,000 to $59,000.
Non-monetized Benefits	Health effects from exposure to HAP (39,000 tons of HCl, 500 tons of HF, 3,100 to 5,300 pounds of Hg and 2,500 tons of other metals). Health effects from exposure to other criteria pollutants (180,000 tons of CO and 572,000 tons of SO_2). Ecosystem effects. Visibility impairment.	

[1] All estimates are for the implementation year (2015), and are rounded to two significant figures.

[2] The total monetized co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors such as directly emitted particles, SO_2, and NO_X and reducing exposure to ozone through reductions of VOC. It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Monetized benefits are shown as a range from Pope et al. (2002) to Laden et al. (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to support the development of differential effects estimates by particle type. These estimates include the energy disbenefits valued at $24 million (using the 3 percent discount rate), which do not change the rounded totals. CO_2-related disbenefits were calculated using the ''social cost of carbon,'' which is discussed further in the RIA.

[3] The methodology used to estimate social costs for one year in the multimarket model using surplus changes results in the same social costs for both discount rates.

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

ACC American Chemistry Council
ACCCI American Coke and Coal Chemicals Institute
AF&PA American Forest and Paper Association
AHFA American Home Furnishings Alliance
AISI American Iron and Steel Institute
AMP American Municipal Power Inc.
AIE Alliance for Industrial Efficiency
APCD air pollution control devices
API American Petroleum Institute
AIF Auto Industry Forum
BFG Blast furnace gas
BLDS Bag leak detection system
BCSE The Business Council for Sustainable Energy
CIBO Council of Industrial Boiler Owners
CO Carbon monoxide
CO_2 Carbon dioxide
CEMS Continuous emissions monitoring system
CEG Citizens Energy Group
CAA Clean Air Act
CFR Code of Federal Regulations
CPMS Continuous parameter monitoring system
CMI CraftMaster Manufacturing Inc.
ERT Electronic Reporting Tool
ESP Electrostatic precipitator
EPA Environmental Protection Agency
FBC Fluidized bed combustion
FR Federal Register
FSI Florida Sugar Industry
GPSP Great Plains Synfuels Plant
HAP Hazardous air pollutants
HBES Health-based emissions standard
HF Hydrogen fluoride
Hg Mercury
HCl Hydrogen chloride
kWh Kilowatt hours
ISO International Standards Organization
lb Pounds
LFG Landfill gas
MACT Maximum achievable control technology
MATS Mercury Air Toxics Standards
MSU Michigan State University
MMBtu Million British thermal units
NESHAP National Emission Standards for Hazardous Air Pollutants
NPRA National Petrochemical and Refiners Association
NTTAA National Technology Transfer and Advancement Act
NAICS North American Industry Classification System
NO_X Nitrogen oxide
NSR New Source Review
OMB Office of Management and Budget
PM Particulate matter
PSU Penn State University
PS Performance Specification
ppm Parts per million
QA Quality assurance
QC Quality control
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
RPU Rochester Public Utilities
RTC Response to comment
SCR Selective catalytic reduction
SNCR Selective non-catalytic reduction
SO_2 Sulfur dioxide
TBtu/yr Trillion British thermal units per year
THC Total hydrocarbon
TSM Total selected metals
TTN Technology Transfer Network
tpy Tons per year
UMRA Unfunded Mandates Reform Act of 1995
U.S. United States
USCHPA US Clean Heat Power Association
US Sugar United States Sugar Corporation
UPL Upper prediction limit
UARG Utility Air Regulatory Group
VCS Voluntary Consensus Standards
VOC Volatile organic compounds
WM Waste Management Inc.
WEPCO Wisconsin Electric Power Company
WWW Worldwide Web

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

I. General Information

A. Does this action apply to me?

The regulated categories and entities potentially affected by this action include:

TABLE 2—POTENTIAL REGULATED CATEGORIES AND ENTITIES AFFECTED

Category	NAICS code[1]	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.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this reconsideration action. To determine whether your facility may be affected by this reconsideration action, you should examine the applicability criteria in 40 CFR 63.7485 of subpart DDDDD (National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers and Process Heaters). If you have any questions regarding the applicability of this final rule to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative, as listed in 40 CFR 63.13 of subpart A (General Provisions).

B. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of this action will also be available on the WWW through the TTN. Following signature, a copy of the action will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg/*. The TTN provides information and technology exchange in various areas of air pollution control.

C. Judicial Review

Under the CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by April 1, 2013. 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

A. Chronological History of Related Actions

On March 21, 2011, the EPA issued final standards for new and existing industrial, commercial, and institutional boilers and process heaters, pursuant to its authority under section 112 of the CAA. On the same day as the final rule was issued, the EPA stated in a separate notice that it planned to initiate a reconsideration of several provisions of the final rule. This reconsideration notice identified several provisions of the March 2011 final rule where additional public comment was appropriate. This notice also identified several issues of central relevance to the rulemaking where reconsideration was appropriate under CAA section 307(d).

On May 18, 2011, the EPA issued a notice to postpone the effective date of the March 21, 2011 final rule. Following promulgation of the final rule, the EPA received petitions for reconsideration from the following organizations

(''Petitioners''): AIE, USCHPA, Alyeska Pipeline, ACC, AHFA, AISI, ACCCI, AMP, API, NPRA, AIF, Citizens Energy Group (CEG), CIBO, CMI, District Energy St. Paul, FSI, GPSP, Hovensa L.L.C., Tesoro Hawaii Corp., Industry Coalition (AF&PA *et al.*), JELD–WEN Inc., MSU, PSU, Purdue University, Renovar Energy Corp., RPU, Sierra Club, Southeastern Lumber Manufacturers Association, State of Washington Department of Ecology, BCSE, UARG, US Sugar, WM and WEPCO. Copies of these petitions are provided in the docket (see Docket ID No. EPA–HQ–OAR–2002–0058). Petitioners, pursuant to CAA section 307(d)(7)(B), requested that the EPA reconsider numerous provisions in the rule. On December 23, 2011, the EPA granted the petitions for reconsideration on certain issues, and proposed certain revisions to the final rule in response to the reconsideration petitions and to address the issues that the EPA previously identified as warranting reconsideration. That proposal solicited comment on several specific aspects of the rule, including:

• Revising the proposed subcategories.
• Solicitation of new data or corrections to existing data to revise emission standards calculations.
• Establishing an alternative TSM limit.
• Appropriateness of an alternative TSM limit for the liquid subcategories.
• Establishing work practice standards for dioxin/furan emissions.
• Revising the efficiency assumptions for the alternative output-based emission standards.
• Accommodating emissions averaging provisions in the alternative output-based emission standards.
• Establishing a mercury fuel specification through which gas-fired boilers that use a fuel other than natural gas or refinery gas may be considered Gas 1 units.
• Establishing a work practice standard for limited use units.
• Providing an affirmative defense for malfunction events.
• Revisions to the monitoring requirements for oxygen in the March 2011 final rule.
• Establishing a full-load stack test requirement for carbon monoxide coupled with continuous oxygen (oxygen trim) monitoring.
• Revising PM monitoring requirements from CEMS to CPMS and exempting biomass units from PM CPMS requirements.
• Revising mercury monitoring requirements to allow for an alternative mercury CEMS.
• Considering use of SO_2 CEMS to demonstrate compliance with HCl limits.
• Minimum data availability provisions.
• Averaging times for monitored parameters and pollutants.
• Revised methods for computing minimum detection levels.
• Providing an alternative CO emission limit based on CO CEMS data.
• Soliciting additional data to set MACT floor emission limits for non-continental liquid units.
• Selecting a 99 percent confidence interval for setting the CO emission limit.
• Tune-up frequencies, timing of initial tune-ups and adjusted tune-up requirements for shutdown units.
• Scope and duration of the energy assessment and deadline for completing the assessment.
• Revising work practices during startup and shutdown.
• Revisions to certain exemptions, including units serving as control devices, waste heat process heaters, units firing comparable fuels and residential units.
• Revisions to reduced testing frequency for emission limits that are established at minimum detection levels.
• Removing fuel analysis requirements for gas 1 fuels at co-fired units.
• Revisions to automating techniques for coal sampling.
• Revisions to emissions averaging across subcategories when units opt to switch to natural gas.
• Consideration of a new subcategory for units installed and used in place of flares.

In this action, the EPA is finalizing multiple changes to the March 2011 final rule after considering public comments on the items under reconsideration.

III. Summary of This Final Rule

As stated above, the December 23, 2011 proposed rule addressed specific issues and provisions the EPA identified for reconsideration. This summary of the final rule reflects the changes to 40 CFR part 63, subpart DDDDD (March 21, 2011 final rule) in regards to those provisions identified for reconsideration and on other discrete matters identified in response to comments or data received during the comment period. Information on other provisions and issues not proposed for reconsideration is contained in the notice and record for the 2011 final rule. [See 76 FR 15608]

This section summarizes the requirements of this action. Section IV below provides a summary of the significant changes to the March 21, 2011 final rule.

A. What is an affected source?

This final rule revises the list of exemptions in § 63.7491 to include residential boilers that may be located at an industrial, commercial or institutional major source. The exemption for boilers or process heaters used specifically for research and development has been revised to include boilers used for certain testing purposes.

B. What are the subcategories of boilers and process heaters?

In this final rule, we are finalizing separate subcategories for heavy liquid-fired, light liquid-fired and liquid-fired units in non-continental locations for PM and CO, pollutants that are dependent on combustor design. In addition, a new subcategory for coal-fired fluidized bed boilers with integrated fluidized bed heat exchangers has been included in the final rule for CO which is dependent on boiler design. Finally, we are finalizing the subcategory for PM at coal/fossil solid units across all coal combustor designs.

C. What emission limits and work practice standards are being finalized?

You must meet the emission limits presented in Table 3 of this preamble for each subcategory of units listed in the table. This final rule includes 19 subcategories, which are based on unit design. New and existing units in three of the subcategories are subject to work practices standards in lieu of emission limits for all pollutants. Numeric emission limits are finalized for new and existing sources in each of the other 16 subcategories.

The changes associated with the emission limits are due to new data, corrections to old data, and inventory changes. In summary, for existing subcategories, for the HCl emission limits, 10 are more stringent, 3 are less stringent and 1 remained the same from the March 21, 2011 final rule; for the mercury emission limits, 3 are more stringent and 11 are less stringent from the March 21, 2011 final rule; for the PM emission limits, 2 are more stringent, 7 are less stringent and 5 are unchanged from the March 21, 2011 final rule; and for the CO emission limits, 4 are more stringent and 10 are less stringent from the March 21, 2011 final rule. For new subcategories, for the HCl emission limits, 13 are less stringent and 1 is unchanged from the March 21, 2011 final rule; for the mercury emission limits, 11 are more stringent, 2 are less stringent and 1 is unchanged from the March 21, 2011 final rule; for the PM emission limits, 9 are less stringent and 5 are unchanged from the March 21, 2011 final rule; and for the CO emission limits, 3 are more stringent and 11 are less stringent from the March 21, 2011 final rule.

TABLE 3—EMISSION LIMITS FOR BOILERS AND PROCESS HEATERS

[lb/MMBtu heat input basis unless noted; alternative output based limits are not shown in the summary table below]

Subcategory	Filterable PM (or total selected metals) (lb per MMBtu of heat input) [a]	HCl (lb per MMBtu of heat input) [a]	Mercury (lb per MMBtu of heat input) [a]	CO (ppm @3% oxygen) [a]	Alternate CO CEMS limit, (ppm @3% oxygen) [b]
Existing—Coal Stoker	0.040 (5.3E–05)	0.022	5.7E–06	160	340
Existing—Coal Fluidized Bed	0.040 (5.3E–05)	0.022	5.7E–06	130	230
Existing—Coal Fluidized Bed with FB heat exchanger	0.040 (5.3E–05)	0.022	5.7E–06	140	150
Existing—Coal-Burning Pulverized Coal	0.040 (5.3E–05)	0.022	5.7E–06	130	320
Existing—Biomass Wet Stoker/Sloped Grate/Other	0.037 (2.4E–04)	0.022	5.7E–06	1,500	720
Existing—Biomass Kiln-Dried Stoker/Sloped Grate/Other	0.32 (4.0E–03)	0.022	5.7E–06	460	ND
Existing—Biomass Fluidized Bed	0.11 (1.2E–03)	0.022	5.7E–06	470	310
Existing—Biomass Suspension Burner	0.051 (6.5E–03)	0.022	5.7E–06	2,400	[c] 2,000
Existing—Biomass Dutch Ovens/Pile Burners	0.28 (2.0E–03)	0.022	5.7E–06	770	[c] 520
Existing—Biomass Fuel Cells	0.020 (5.8E–03)	0.022	5.7E–06	1,100	ND
Existing—Biomass Hybrid Suspension Grate	0.44(4.5E–04)	0.022	5.7E–06	2,800	900
Existing—Heavy Liquid	0.062 (2.0E–04)	0.0011	2.0E–06	130	ND
Existing—Light Liquid	0.0079 (6.2E–05)	0.0011	2.0E–06	130	ND
Existing—non-Continental Liquid	0.27 (8.6E–04)	0.0011	2.0E–06	130	ND
Existing—Gas 2 (Other Process Gases)	0.0067 (2.1E–04)	0.0017	7.9E–06	130	ND
New—Coal Stoker	0.0011 (2.3E–05)	0.022	8.0E–07	130	340
New—Coal Fluidized Bed	0.0011 (2.3E–05)	0.022	8.0E–07	130	230
New—Coal Fluidized Bed with FB Heat Exchanger	0.0011 (2.3E–05)	0.022	8.0E–07	140	150
New—Coal-Burning Pulverized Coal	0.0011 (2.3E–05)	0.022	8.0E–07	130	320
New—Biomass Wet Stoker/Sloped Grate/Other	0.030 (2.6E–05)	0.022	8.0E–07	620	390
New—Biomass Kiln-Dried Stoker/Sloped Grate/Other	0.030 (4.0E–03)	0.022	8.0E–07	460	ND
New—Biomass Fluidized Bed	0.0098 (8.3E–05)	0.022	8.0E–07	230	310
New—Biomass Suspension Burner	0.030 (6.5E–03)	0.022	8.0E–07	2,400	[c] 2,000
New—Biomass Dutch Ovens/Pile Burners	0.0032 (3.9E–05)	0.022	8.0E–07	330	[c] 520
New—Biomass Fuel Cells	0.020 (2.9E–05)	0.022	8.0E–07	910	ND
New—Biomass Hybrid Suspension Grate	0.026 (4.4E–04)	0.022	8.0E–07	1,100	900
New—Heavy Liquid	0.013 (7.5E–05)	4.4E–04	4.8E–07	130	ND
New—Light Liquid	0.0011 (2.9E–05)	4.4E–04	4.8E–07	130	ND
New—Non-Continental Liquid	0.023 (8.6E–04)	4.4E–04	4.8E–07	130	ND
New—Gas 2 (Other Process Gases)	0.0067 (2.1E–04)	0.0017	7.9E–06	130	ND

NA-Not applicable; ND-No data available
[a] 3-run average, unless otherwise noted.
[b] 30-day rolling average, unless otherwise noted.
[c] 10-day rolling average.

We also are finalizing a work practice standard for dioxin/furan emissions from all subcategories.

D. What are the requirements during periods of startup and shutdown?

We are finalizing revised work practice standards for periods of startup and shutdown to better reflect the maximum achievable control technology during those periods. In addition, we are finalizing definitions of startup and shutdown. We are defining startup as the period between the state of first-firing of fuel in the unit after a shutdown to the period where the unit first supplies steam. We are defining shutdown as the period that begins when no more steam is supplied or at the point of no fuel being fired in the unit. For periods of startup and shutdown, we are finalizing the following work practice standard: You must operate all continuous monitoring systems during startup and shutdown. For startup, you must use one or a combination of the listed clean fuels. Once you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must engage all of the applicable control devices except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR. You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR systems as expeditiously as possible. During shutdown while firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR. You must comply with all applicable emissions and operating limits at all times the unit is in operation except for periods that meet the definitions of startup and shutdown in this subpart, during which times you must comply with these work practices. You must keep records during periods of startup or shutdown. You must keep records concerning the date, duration, and fuel usage during startup and shutdown.

E. What are the testing and initial compliance requirements?

We are requiring that the owner or operator of a new or existing boiler or process heater conduct performance tests to demonstrate compliance with all applicable emission limits. This final rule adds the requirement to conduct initial and annual stack tests to determine compliance with the TSM emission limits using EPA Method 29 for those subcategories with alternate TSM limits.

F. What are the continuous compliance requirements?

This final rule removes the requirement for units combusting biomass with heat input capacities of 250 MMBtu/hr or greater to install, certify, maintain and operate a CEMS measuring PM emissions. This final rule requires units combusting solid fossil fuel or heavy liquid with heat input capacities of 250 MMBtu/hr or greater to install, certify, maintain, and operate PM CPMS. Moreover, owners or operators of units combusting solid fossil fuel or heavy liquid with heat input capacities of 250 MMBtu/hr or greater are allowed to install, certify, maintain and operate PM CEMS as an alternative to the use of PM CPMS, consistent with regulations for similarly-sized commercial and industrial solid waste incinerators units and EGUs subject to the MATS. Just as units using PM CPMS will not be required to conduct parameter monitoring for PM, units using PM CEMS will not be required to conduct parameter monitoring for PM.

This final rule also includes an alternative method of demonstrating continuous compliance with the HCl emission limit. This method allows using SO_2 emissions as an alternate operating limit. This method of demonstrating continuous compliance will be allowed only on a unit that utilizes a SO_2 CEMS and an acid-gas control technology including wet scrubber, dry scrubbers and duct sorbent injection. Boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO_2 CEMS would be required to maintain the 30-day rolling average SO_2 emission rate at or below the highest hourly average SO_2 concentration measured during the most recent HCl performance test.

G. What are the compliance dates?

For existing sources, the EPA is establishing a compliance date of January 31, 2016. New sources must comply by January 31, 2013, or upon startup, whichever is later. New sources are defined as sources which commenced construction or reconstruction on or after June 4, 2010 pursuant to section 112(a)(4).

Commenters have argued that the 3-year compliance deadline the EPA is establishing for existing sources to meet the standards does not provide them with sufficient time to meet the standards in view of the large number of sources that will be competing for the needed resources and materials from engineering consultants, permitting authorities, equipment vendors, construction contractors, financial institutions, and other critical suppliers.

As an initial matter, we note that many sources subject to the emission standards in the final rule should be able to meet the standards within three years, even those that need to install pollution control technologies to do so. In addition, many sources subject to the rule are gas fired units or small boilers (less than 10 MMBtu/hr) and will not need to install controls in order to demonstrate compliance, as these sources are subject to work practice standards. For these sources, the 3-year compliance deadline is highly unlikely to be problematic either in general, or with respect to the claims commenters have made about the possibility that the demand for resources related to control technology will exceed the supply.

At the same time, the CAA allows title V permitting authorities to grant sources, on a case-by-case basis, extensions to the compliance time of up to one year if such time is needed for the installation of controls. *See* CAA section 112(i)(4)(i)(A). Permitting authorities are already familiar with, and in many cases have experience with, applying the 1-year extension authority under section 112(i)(4)(A) since the provision applies to all NESHAP. We believe that should the range of circumstances that commenters have cited as impeding sources' ability to install controls within three years materialize, then it is reasonable for permitting authorities to take those circumstances into consideration when evaluating a source's request for a 1-year extension, and where such applications prove to be well-founded, it is also reasonable for permitting authorities to make the 1-year extension available to applicants.

In making a determination as to whether an extension is appropriate, we believe it is also reasonable for permitting authorities to consider the large number of pollution control retrofit projects being undertaken for purposes of complying either with the standards in this rule or with those of other rules such as MATS for the power sector that may be competing for similar resources.

Further, commenters have pointed out that in some cases operators of existing sources that are subject to these standards and that generate energy may opt to meet the standards by terminating operations at these sources and building new sources to replace the energy generation at the shut-down sources. While the ultimate discretion to provide a 1-year extension lies with the permitting authority, the EPA believes that it is reasonable for permitting authorities to allow the fourth year extension for the installation of replacement sources of energy generation at the site of a facility applying for an extension for that purpose. Specifically, the EPA believes where an applicant demonstrates that it is building replacement sources of energy generation for purposes of meeting the requirements of these standards such a replacement project could be deemed to constitute the ''installation of controls'' under section 112(i)(3)(B).

In a case where pollution controls are being installed or onsite replacement energy generation is being constructed to allow for retirement of older, under-controlled energy generation units, a determination that an extra year is necessary for compliance should be relatively straightforward. In order to install controls, companies are likely to undertake a number of steps relatively soon after the effective date of the rule, including obtaining necessary building and environmental permits and hiring contractors to perform the construction of the emission controls or replacement energy generation units. This should provide sufficient information for a permitting authority to determine that emission controls are being installed or that replacement energy generation is being constructed. As a result, a permitting authority will be in a position to make a determination as to whether a source's compliance schedule will exceed 3 years and to quickly make a determination as to when an extension is appropriate.

In sum, the EPA believes that although most, if not all, units will be able to fully comply with the standards within 3 years, the fourth year that permitting authorities are allowed to grant for installation of controls is an important flexibility that will address situations where an extra year is necessary. Of course in situations where EPA is the permitting authority, we would also consider the above circumstances when acting on a permit application.

IV. Summary of Significant Changes Since Proposal

The EPA has made numerous changes in this final rule from the proposal after consideration of the public comments received. Most are changes to clarify applicability and implementation issues raised by the commenters. The public comments received on the proposed changes and the responses to them can be viewed in the memorandum ''Response to Comments for Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants'' located in the docket.

A. Applicability

Since proposal, the EPA has made certain changes to the applicability of this final rule. We have clarified that the exemption for boilers and process heaters used for research and development includes boilers used for testing the propulsion systems on military vessels. This is consistent with the intent of the exemption in that these test boilers do not provide steam for heating, to a process, or other non-propulsion related uses but are used exclusively to test the propulsion systems of nuclear-powered aircraft carriers that are undergoing repair, overhaul, or installation.

B. Subcategories

As described in the preamble to the proposed reconsideration rule, within the basic unit types of boilers and process heaters there are different designs and combustion systems that, while having a minor effect on fuel-dependent HAP emissions, have a much larger effect on pollutants whose emissions depend on the combustion conditions in a boiler or process heater. In the case of boilers and process heaters, the combustion-related pollutants are the organic HAP. In the proposed rule, we identified the following 17 subcategories for organic HAP: (1) Pulverized coal units; (2) stokers designed to burn coal; (3) fluidized bed units designed to burn coal; (4) stokers designed to burn wet biomass; (5) stokers designed to burn kiln-dried biomass; (6) fluidized bed units designed to burn biomass; (7) suspension burners designed to burn biomass; (8) dutch ovens/pile burners designed to burn biomass; (9) fuel cells designed to burn biomass; (10) hybrid suspension grate units designed to burn biomass; (11) units designed to burn heavy liquid fuel; (12) units designed to burn light liquid fuel; (13) non-continental liquid units; (14) units designed to burn natural gas/refinery gas; (15) units designed to burn other gases; (16) metal process furnaces; and (17) limited-use units.

In this final rule, we are also adding a separate subcategory for fluidized bed units with a fluidized bed heat exchanger designed to burn coal and adjusted the definition of the limited use subcategory.

Fluidized bed boilers are designed to combust fuel with relatively low heating value and high ash compared to other combustor designs. Two fuel properties of coal are heating values and ash content. As the heating value of the coal decreases, ash content increases. Fluidized bed boilers are designed to have large tube surface areas to transfer heat from the fuel through the process of conduction and convection, but in some cases the amount of tube surface area in the furnace for heat transfer is insufficient. In order to overcome insufficient heat exchange, certain fluidized bed boilers adopt a fluidized bed heat exchanger design to achieve heat transfer. The fluidized bed heat exchanger is located at the exit of the cyclone section of the unit. This design allows the boiler to combust coal with a lower heating value than a coal-fired fluidized bed boiler without a fluidized bed heat exchanger. Therefore, because this boiler design does have different combustion-related HAP emission characteristics, a new subcategory of coal fluidized bed with integrated heat exchanger was added to the final rule.

The EPA is also revising the definition of the limited use subcategory. Many affected units operate on standby mode or low loads for periods longer than the proposed definition for limited use units, which limited operation to 876 hours per year. By converting to a capacity-factor approach, we are allowing more flexibility on unit operations without increasing emissions or harm to human health and the environment. For example, units operating at 10 percent load for 8,760 hours per year would emit the same amount of emissions as units operating at full load for 876 hours per year. Further, 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. The limited use subcategory was adjusted to be based on units with a federally enforceable operating limit of less than or equal to 10 percent of an average annual capacity factor.

C. Performance Test Requirements

Table 5 of this final rule has been revised to add performance test procedures for conducting performance stack tests for demonstrating compliance with the alternate TSM emission limits. In the reconsideration proposal, we proposed emissions limits for TSM (i.e., arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium) as an alternative to the proposed PM emission limits for many of the subcategories. In the preamble to the proposed rule, we added procedures in Table 6 of the rule for conducting fuel analysis for total selected metals but we inadvertently failed to add performance test requirements for stack sampling of TSM emissions in Table 5 of the rule.

D. Emission Limits

One significant change since proposal is related to the PM emission limits for the coal subcategories. Several petitioners disagreed with EPA's position to set different PM limits for subcategories of boilers and process heaters based on the fuel used, and instead offered information to support the position that PM should be considered a combustion-based pollutant. The differences in PM particle size, fouling characteristics and feasibility of certain control technologies on certain unit designs suggested that PM is more appropriately classified as a combustion-based pollutant, but only for the coal subcategories. After assessing the points raised by the petitioners, the EPA agreed that PM emissions are influenced by unit design, and fuel type, and proposed to create combustion-based pollutant subcategories for coal and solid fuels and create fuel-based subcategories for liquid and biomass fuel units. The EPA is finalizing a single PM limit for all coal/solid fossil fuel subcategories, and is also finalizing emissions limits based on PM as a combustion-based pollutant for the biomass and liquid fuel subcategories.

Another change from proposal is that the alternative TSM emission limits are now applicable to the three liquid fuel subcategories. Several commenters provided data and comments supporting these alternative emission standards for non-mercury metallic HAP. After assessing the revised data and the points made by the commenters, the EPA agrees that the limited data available for liquid fuel units are not unique to this subcategory. Based on the EPA agreeing with the commenters, the EPA re-calculated the TSM emission limits for the liquid fuel subcategories and included them in the final rule.

The CO emission limit for several subcategories, both new and existing, have been revised to reflect a CO level that is consistent with MACT for organic HAP reduction. Several commenters recommended that the EPA evaluate a minimum CO standard (i.e., 100 ppm corrected to 7 percent oxygen) to serve as a lower bound surrogate for organic HAP. Commenters also provided data and information to support such a standard, and noted that the EPA has taken a similar approach in other emission standards under section 112.

The EPA evaluated whether there is a minimum CO level for boilers and process heaters below which there is no further benefit in organic HAP reduction/destruction. Specifically, we evaluated the relationship between CO and formaldehyde using the available data obtained during the rulemaking. Formaldehyde was selected as the basis of the organic HAP comparison because it is the most prevalent organic HAP in the emission database and a large number of paired tests existed for boilers and process heaters for CO and formaldehyde. The paired data show decreasing formaldehyde emissions with decreasing CO emissions down to CO levels around 300 ppm, supporting the selection of CO as a surrogate for organic HAP emissions. A slight increase in formaldehyde emissions is observed at CO levels below around 200 ppm, suggesting a breakdown in the CO-formaldehyde relationship at low CO levels. At levels lower than 150 ppm, the mean levels of formaldehyde appear to increase, as does the overall maximum value of and variability in formaldehyde emissions. However, we are aware of no reason why CO concentrations would continue to decrease and formaldehyde concentrations would increase as combustion conditions improve. It is possible that imprecise formaldehyde measurements at low concentrations (i.e., 1–2 ppm) may account for this slight increase in formaldehyde emissions observed at CO levels below 100 ppm corrected to 7 percent oxygen. Based on this, we do not believe that such measurements are sufficiently reliable to use as a basis for establishing an emissions limit.

Therefore, based on the above analysis, we are promulgating a minimum MACT floor level for CO of 130 ppm corrected to 3 percent oxygen (which is equivalent to 100 ppm corrected to 7 percent oxygen). We note this is the same approach used to establish the CO emission limit of 100 ppm corrected to 7 percent oxygen for the Burning of Hazardous Waste in Boilers and Industrial Furnaces rule. Additional discussion of the rationale for this approach can be found in the memorandum ''Revised MACT Floor Analysis (August 2012) for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source.''

Subcategories where the initial MACT floor 99 percent UPL calculations for CO were less than 100 ppm corrected to 7 percent oxygen (or equivalently 130 ppm corrected to 3 percent oxygen) are as follows:

- New and Existing Subcategories: Coal-FB, Coal-PC, Heavy Liquid, Light Liquid, Non-Continental Liquid, Process Gas
- New Subcategories: Coal-Stoker

We believe a CO level of 130 ppm corrected to 3 percent oxygen is an appropriate minimum MACT floor level. Although some measurements show CO levels below 130 ppm corrected to 3 percent oxygen, it is not appropriate to establish a lower floor level because CO is a conservative surrogate for organic HAP. In other words, organic HAP emissions are extremely low when sources operate under the good combustion conditions required to achieve CO levels in the range of zero to 100 ppm. As such, lowering the CO floor below 100 ppm will not provide reductions in organic HAP emissions. There are myriad factors that affect combustion efficiency and, as a function of combustion efficiency, CO emissions. As combustion conditions improve and hydrocarbon levels decrease, the larger and easier to combust compounds are oxidized to form smaller compounds that are, in turn, oxidized to form CO and water. As combustion continues, CO is then oxidized to form carbon dioxide and water. Because CO is a difficult to destroy refractory compound (*i.e.,* oxidation of CO to carbon dioxide is the slowest and last step in the oxidation of hydrocarbons), it is a conservative surrogate for destruction of hydrocarbons, including organic HAP.

The conservative nature of CO as an indicator of good combustion practices is supported by our data. At CO levels less than 100 ppm corrected to 7 percent oxygen, our data indicate that there is no apparent relationship between CO and organic HAP (i.e., formaldehyde). For example, a source with a CO level of 20 ppm may have the same measured formaldehyde as a source achieving a CO emission level of 100 ppm corrected to 7 percent oxygen. Sources are required to establish operating requirements based on operating levels that were demonstrated during the test. Sources must comply with these operating requirements on a continuous basis. Compliance with these requirements adequately assures sources will be controlling organic HAP emissions to MACT levels.

As detailed in the docketed memorandum ''Beyond the Floor Technology Analysis for Major Source Boilers and Process Heaters (Revised August 2012),'' we reviewed the emission limits that are becoming less stringent since the March 2011 final rule in order to assess whether a beyond the floor option was technically achievable and cost effective. As a result of this review, the PM emission limits for several new biomass subcategories have been changed to reflect a beyond the floor limit of 0.03 lb/MMBtu, based on the limit for new biomass boilers in 40 CFR part 60 subparts Db and Dc. Due to the low mercury emission limits for new solid fuel boilers, these new biomass units are expected to install a fabric filter level of control in order to meet the new source mercury limits for the solid fuel subcategory. This mercury control has the co-benefit of reducing PM emissions down to levels of 0.03 lb/MMBtu so there is no incremental cost to achieve these additional reductions in PM for the biomass units that have a design heat input capacity between 10 and 30 MMBtu/hr. For units with a design heat input capacity of 30 MMBtu/hr or greater, these units are already subject to a PM limit of 0.03 lb/MMBtu and adjusting these new source limits to this level of control makes the limits consistent between both rules, without adding additional costs. We 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.

The other changes associated with the other emission limits are due to new data, corrections to old data, and inventory changes. In summary, compared to the December 23, 2011 proposed limits for existing units, the final HCl emission limits remained the same; for the final mercury emission limits, 3 are more stringent, 10 are less stringent and 1 is unchanged; for the final PM emission limits, 3 are more stringent, 5 are less stringent and 6 are unchanged; and for the final CO emission limits, 3 are more stringent and 11 are less stringent. For new units, compared to the proposed emission limits, 3 of the final HCl emission limits are more stringent and 11 remained the same; for the final mercury emission limits, 10 are more stringent and 4 are unchanged; for the final PM emission limits, 5 are more stringent, 2 are less stringent and 7 are unchanged; and for the final CO emission limits, 2 are more stringent, 11 are less stringent and 1 is unchanged.

E. Work Practice Requirement

In this final rule several changes have been made to the work practice requirement to conduct a tune-up. First, the requirement to inspect the burner has been revised to allow units that sell electricity to schedule the burner inspection, as well as the air-to-fuel system inspection, at the time of the first outage but not to exceed 36 months from the previous inspection. This change is being made to this final rule because commenters stated that large boilers that serve electricity for sale may not require annual outages and would, therefore, need to be taken off-line for the sole purpose of an annual tune-up. This frequency is consistent with the requirements of the NESHAP for electric utility boilers (40 CFR part 63, subpart UUUUU).

Also, for 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 into process equipment. Commenters indicated that some process heaters are installed inside tanks and entry into the tank to access the heater may not occur within a 5 year period.

The requirement to optimize total emissions of CO has been revised to require that this optimization not only be consistent with the manufacturer's specifications but also with any NO_X emission requirement to which the unit is subject. Some commenters indicated that many boilers need different tune-up criteria due to their requirement to also comply with low NO_X emission limits. We are also aware that several states have boiler tune-up requirements to minimize NO_X emissions first and then optimize CO emissions.

We have added boilers or process heaters that have a continuous oxygen trim system to the types of boilers or process heaters that must conduct a tune-up every 5 years. These units do not need to be tuned as frequently because the trim system is designed to continuously measure and maintain an optimum air to fuel ratio which is the purpose of a tune-up.

F. Averaging Times Definitions

We revised the definitions of ''30-day rolling average'' and ''daily block average'' to exclude periods of startup and shutdown or downtime from the arithmetic mean. Commenters requested that the EPA specify how a 30-day rolling average is calculated and whether it includes the previous 720 hours of valid operating data and that the valid data exclude hours during startup and shutdown as well as unit down time. We agree with the commenters that the definitions need clarification and that these periods should not be included in calculating the 30-day rolling average. Therefore, we have revised the definitions accordingly.

We have also included in the final rule a definition of ''10-day rolling average'' that is consistent with the revised definition of ''30-day rolling average.''

G. Energy Assessment

In this final rule, we have revised the definition of energy assessment per the requirements of Table 3 of this final rule by providing duration for performing the energy assessment for large fuel use facilities. In numbered paragraph (3) in the definition of ''Energy assessment'' in § 63.7575, which is for facilities with units having a combined heat input capacity greater than 1 TBtu/yr, we added time duration/size ratio and included a cap to the maximum number of on-site technical hours that should be used in the energy assessment. This addition of a duration for large fuel use facilities is being made to be consistent with durations specified for small [paragraph (1) in the definition of ''Energy assessment''] and medium [paragraph (2) in the definition of ''Energy assessment''] fuel use facilities. The energy assessment for facilities with affected boilers and process heaters having a combined heat input capacity greater than 1.0 TBtu/yr will be up to 24 on-site technical labor hours for the first TBtu/yr plus 8 technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 technical hours, but may be longer at the discretion of the owner or operator.

The revised definition of energy assessment also clarifies our intentions that the scope of assessment is based on energy use by discrete segments of a facility and not by a total aggregation of all individual energy using elements of a facility. The applicable discrete segments of a facility could vary significantly depending on the site and its complexity. We have added the following paragraph (4), to the energy assessment definition to help resolve current problems in identifying the scope of the various energy use systems in a large industrial complex and allow for more streamlined assessments:

''(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy output in (1), (2) and (3) above 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).''

We have also revised paragraph 4 of Table 3 of the final rule to allow a source that is operating under an energy management program established through energy management systems compatible with ISO 50001, which includes the affected units, to satisfy the energy assessment requirement. We consider these energy management programs to be equivalent to the one-time energy assessment because facilities having these programs operate under a set of practices and procedures designed to manage energy use on an ongoing basis. These programs contain energy performance measurements and tracking plans with periodic reviews.

The definition of ''Energy use system'' has also been revised in this final rule to clarify that energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

H. Startup and Shutdown Definitions

A number of commenters indicated that the proposed load specifications (i.e., 25 percent load) within the definitions of ''startup'' and ''shutdown'' were inconsistent with either safe or normal (proper) operation of the various types of boilers and process heaters encountered within the source category. As the basis for defining periods of startup and shutdown, a number of commenters suggested alternative load specifications based on the specific considerations of their boilers; other commenters suggested the achievement of various steady-state conditions.

We have reviewed these comments and believe adjustments are appropriate in the definition of ''startup'' and ''shutdown.'' These adjustments are tailored for industrial boilers and are consistent with the definitions of ''startup'' and ''shutdown'' contained in the 40 CFR part 63, subpart A General Provisions. We believe these revised definitions address the comments and are rational based on the fact that industrial boilers function to provide steam or, in the case of cogeneration units, electricity; therefore, industrial boilers should be considered to be operating normally at all times steam 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. The definitions of ''startup'' and ''shutdown'' have been revised in the final rule as follows:

''*Startup* means either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler or process heater after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler or process heater is supplied for heating and/or producing electricity, or for any other purpose.''

''*Shutdown* means the cessation of operation of a boiler or process heater for any purpose. Shutdown begins either when none of the steam and heat from the boiler or process heater is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler or process heater, whichever is earlier. Shutdown ends when there is both no steam or heat being supplied and no fuel being fired in the boiler or process heater.''

The EPA is requiring sources to vent emissions to the main stack(s) and operate all control devices necessary to meet the normal operating standards under this final rule (with the exception of limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR) when firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel or gas 2 (other) gases in the boiler or process heater during startup or shutdown. It is the responsibility of the operators of affected boilers and process heaters to start their limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR systems appropriately to comply with relevant standards applicable during normal operation. Startup ends and normal operating standards apply when heat or steam is supplied for any purpose.

The EPA carefully considered fuels and potential operational constraints of APCD when designing its work practices for periods of startup and shutdown. The EPA notes that there is no technical barrier to burning clean fuels (e.g., natural gas, distillate oil) for longer portions of startup or shutdown periods at a boiler and the HAP emission reduction benefits warrant additional utilization of such fuels until the temperature and stack emissions pressure is sufficient to engage the APCD. The EPA is aware that SNCR and SCR systems with ammonia injection need to be operated within a prescribed and relatively narrow temperature window to provide NO_X reductions. Further, the EPA is aware that dry scrubbers also need to be operated close to flue gas saturation temperature, and that fabric filters need to be operated at temperatures above the acid dew point. Because these devices have specific temperature requirements for proper operation, the EPA notes in its work practices that it is the responsibility of the operators of affected boilers and process heaters to start their SNCR, SCR, fabric filter and dry scrubber systems appropriately to comply with relevant standards applicable during normal operation.

I. Fuel Sampling Frequency

The sampling frequency for gaseous fuel-fired units that elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory has been revised in this final rule. If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification, no further sampling is required. If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification, only semi-annual sampling need to be conducted. If the initial mercury constituents are greater than 75 percent of the mercury specification, monthly sampling is required.

J. Affirmative Defense

In the proposal, we used terms such as ''exceedance'' or ''excess emissions'' in § 63.7501, which created unnecessary confusion as to when the affirmative defense could be used. In the final amended rule, we have eliminated those terms and used the word ''violation'' to make clear that the affirmative defense to civil penalties is available only where an event that causes a violation of the emissions standard meets the definition of malfunction under § 63.2.

We have also eliminated the 2-day notification requirement that was included in 40 CFR 63.7501(b) at proposal because we expect to receive sufficient notification of malfunction events that result in violations in other required compliance reports, such as the malfunction report required under 40 CFR 63.7550(c). In addition, we have revised the 45-day affirmative defense reporting requirement that was included in 40 CFR 63.7501(b) at proposal to require sources to include the report in the first compliance, deviation or excess emission report due after the initial occurrence of the violation, unless the compliance, deviation or excess emission report is due less than 45 days after the violation. In that case, the affirmative defense report may be included in the second compliance, deviation or excess emission report due after the initial occurrence of the violation. Because the affirmative defense report is now included in a subsequent compliance, deviation or excess emission report, there is no longer a need for the proposed 30-day extension for submitting a stand-alone affirmative defense report. Consequently, we are not including this provision in the final amended rule. We have also re-evaluated the language concerning the use of off-shift and overtime labor to the extent practicable and believe that the language is not necessary. Thus, we have deleted that phrase from section 63.7501(a)(2).

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 June 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) (court declined to remand rule because petitioners failed to show substantial likelihood that final rule would have been changed based on information in 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).

We are denying reconsideration on the following 57 issues contained in the petitions for reconsideration because they failed to meet the standard described above for reconsideration under CAA section 307(d)(7)(B). Specifically, on these issues, the petitioner has failed to show the following: that it was impracticable to raise their objections during the comment period or that the grounds for their objections arose after the close of the comment period; and/or that their concern is of central relevance to the outcome of the rule. Therefore, the EPA is denying the petitions for reconsideration on the issues for the reasons described below.

Issue: Delist gas units.

The petitioners (API, NPRA) requested that the EPA remove gas-fired units from the section 112(c) list of source categories for which the EPA is required to establish emissions standards under section 112(d). The EPA is denying the petition for reconsideration for the following reasons. First, the issue is outside the scope of this rulemaking, which establishes emissions standards for new and existing units within the major source boilers and process heaters source category. The EPA did not solicit comment in the proposed rule regarding the scope of the subcategory. Further, petitioners provide no information to support delisting gas units under section 112(c)(9), which requires the EPA to make certain findings before delisting any sources. In addition, the petition does not address the D.C. Circuit's decision in *NRDC* v. *EPA,* 489 F.3d 1364 (2007), regarding the EPA's ability to delist subcategories of a source category pursuant to section 112(c)(9). For these reasons, the petitions do not provide support for the argument that the regulation should be changed. For this reason, the petition does not demonstrate that the issue is of central relevance to the outcome of the final rule and the EPA is denying the request for reconsideration.

Issue: Exempt natural gas hot water heaters with tanks greater than 120 gallons.

The petitioner (AIF) requested that the EPA exempt natural gas hot water heaters with tanks greater than 120 gallons. While the EPA disagrees with the petitioner regarding whether such units should be subject to the emissions standards in this rule, the petitioner has not demonstrated that it lacked the opportunity to comment on whether such units should be required to meet emissions standards. The EPA proposed work practice standards for such units in its June 2010 proposal, and the petitioner had the opportunity to comment on whether such standards should be applied to such units at all. Therefore, the EPA is denying the request for reconsideration.

Issue: Exempt natural gas and distillate oil-fired circulating hot water systems with a design capacity of 10 MMBtu/hr or less.

The petitioner (CIBO) requested that the EPA exempt natural gas and distillate oil-fired circulation hot water systems that are not greater than 10 MMBtu/hr. While the EPA disagrees with the petitioner regarding whether such units should be subject to the emissions standards in this rule, the petitioner has not demonstrated that it lacked the opportunity to comment on whether such units should be required to meet emissions standards. The EPA proposed emissions standards for such units, and the petitioner had the opportunity to comment on whether such standards should be applied to such units at all. In addition, the petition does not provide any information to demonstrate that these units should be delisted pursuant to section 112(c)(9). Therefore, the EPA is denying the request for reconsideration.

Issue: Confirm in definitions that open flame heaters (e.g., asphalt tank heaters) are not process heaters.

The petitioners (API, NPRA) requested that the EPA clarify in the definition of ''process heater'' that open flame heaters do not meet the definition. While the EPA disagrees with the petitioners whether clarification is needed in regards to open flame heaters, the petitioners have not demonstrated that it lacked the opportunity to comment on the proposed definition. The definition that the EPA proposed clearly states that process heaters are enclosed devices in which the combustion gases do not come into contact with process materials, and as such, does not include open flame heaters. Therefore, the EPA is denying reconsideration.

Issue: For blast furnace fuel-fired boiler exemption, compute the 90 percent BFG by volume threshold to exclude periods of BFG curtailment.

The petitioners (AISI, ACCCI) requested that the EPA revise the exemption for BFG fuel-fired boilers to exclude periods of BFG curtailment. While the EPA disagrees with the petitioners regarding revising the exemption, the petitioners have not demonstrated that it lacked the opportunity to comment on the proposed exemption for BFG fuel-fired boilers. The EPA proposed the exemption for these boilers, and petitioners therefore had the opportunity to comment on whether the exemption should apply to periods of BFG curtailment. Therefore, the EPA is denying the request for reconsideration.

Issue: Exempt boilers whose flue gases are used in direct-fired process heaters subject to other NESHAP.

The petitioner (CMI) requested that the EPA exempt from the rule boilers whose flue gases are used in direct-fired process heaters that are subject to other NESHAP. The final rule does not apply to such units if they are subject to another NESHAP. The EPA does not see a need for further clarification. Since the final rule does in fact exempt these units, the EPA is denying the request for reconsideration.

Issue: Work practice standards do not meet EPA obligations under 112(c)(6).

The petitioner (Sierra Club) requested that the EPA establish numeric emissions limits for Gas 1 units rather than work practice standards. Specifically, the petitioner alleges that the work practice standards do not meet the EPA's obligations under section 112(c)(6) of the CAA, and that it was not the case that data were below the detection level for all HAP emitted from these units. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's arguments regarding the legal authority to establish work practice standards for Gas 1 units and the basis for such standards, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed work practice standards for Gas 1 units and explained in the proposal its rationale for such standards, including the fact that a significant portion of the emissions data were below the detection level. 75 *FR* at 32024–25. Therefore, the petitioner had the opportunity to comment on this issue, and did in fact submit comments regarding the EPA's legal authority to establish work practice standards for Gas 1 units. Therefore, the EPA is denying reconsideration on this issue.

Issue: Work practices for small units are not justified by 112(h) since small units were not given their own subcategory.

The petitioner (Sierra Club) requested that the EPA require small units, those having a heat input capacity of less than 10 MMBtu/hr, to meet numeric emissions limits rather than work practice standards. The EPA is denying the request for reconsideration on this issue because the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed work practice standards for these units and explained in the proposal its rationale for such standards. 75 *FR* at 32024–25. The EPA did in fact receive comments regarding the proposed standards, to which it responded in the final rule. 76 *FR* at 15640. Moreover, the EPA notes that nothing in section 112(h) limits the EPA's discretion to establish work practice standards to the establishment of such standards for an entire category or subcategory. Therefore, the EPA is denying the request for reconsideration.

Issue: PM is not an adequate surrogate for non-mercury metallic HAP.

The petitioner (Sierra Club) requested that the EPA remove the PM standard as a surrogate for non-mercury metallic HAP and instead adopt a numeric limit for non-mercury metallic HAP because PM is not an appropriate surrogate. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding the suitability of PM as a surrogate for non-mercury metallic HAP, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed PM standards as a surrogate for non-mercury metallic HAP and explained in the proposal the agency's basis for concluding that PM was an appropriate surrogate. 75 *FR* at 32018. Therefore, the EPA is denying the request for reconsideration.

Issue: Establish direct limits on organics or select a surrogate besides CO.

The petitioner (Sierra Club) requested that the EPA remove the CO standard as a surrogate for organic HAP and instead adopt a numeric limit for these HAP, because CO is not an appropriate surrogate. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding the suitability of CO as a surrogate for organic HAP, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed CO standards as a surrogate for organic HAP and explained in the proposal the agency's basis for concluding that CO was an appropriate surrogate. 75 *FR* at 32018. The EPA received comments on this issue, including comments stating that CO is not an appropriate surrogate for organic HAP. Therefore, the EPA is denying the request for reconsideration.

Issue: Adopt an alternative THC emission standard.

The petitioner (CIBO) requested that the EPA adopt a THC emissions standard as an alternative to the CO standard. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding whether a THC alternative standard is appropriate as a surrogate for non-dioxin organic HAP, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA raised in the proposal the possibility of THC as a surrogate for non-dioxin organic HAP, and explained why the use of CO as a surrogate was preferable. 75 *FR* at 32018. In addition, the EPA did not receive any comments or data during the public comment period on the proposed rule that would have enabled the agency to establish a THC alternative standard, including THC emissions data, nor did the petitioner provide any such data. Therefore, the petition does not provide substantial support for its argument that the final rule should be changed. For these reasons, the EPA is denying the petition for reconsideration on this issue.

Issue: Regulation of Total dioxin/furans exceeds statutory authority as only 2 compounds are in 112(b)(1).

The petitioners (AISI, ACCCI, AF&PA) alleged that the EPA lacks statutory authority to regulate total dioxin/furans under CAA section 112, and that the EPA's response in the final rule explaining why it is issuing a total dioxin/furan standard was not a logical outgrowth of the proposed rule. The EPA is denying the request for reconsideration on this issue. First, the EPA disagrees that the final rule is not a logical outgrowth of the proposal. The EPA proposed emissions standards for total dioxin/furans and adopted a final emissions standard for the same pollutant. Therefore, the commenter had the opportunity to provide its views during the public comment period regarding the EPA's proposed emissions standard, including its views regarding the EPA's authority to regulate the pollutant at issue. The fact that the EPA responded to those comments does not mean that the petitioner lacked the opportunity to comment—in fact, the petitioner did provide such comments. 76 *FR* at 15640. For this reason, the EPA is denying the petition for reconsideration.

Issue: HCl is an inadequate surrogate for all acid gases.

The petitioner (Sierra Club) requested that the EPA remove the HCl standard as a surrogate for acid gases and instead adopt a numeric limit for these HAP, because HCl is not an appropriate surrogate. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding the suitability of HCl as a surrogate for acid gases, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed HCl standards as a surrogate for acid gases and explained in the proposal the agency's basis for concluding that HCl was an appropriate surrogate. 75 *FR* at 32018. While the EPA had emission data for HCl from hundreds of affected units upon which to establish standards, the EPA did not have sufficient data on the other acid gases to do so (hydrogen fluoride, hydrogen cyanide and chlorine). The petitioner did not refer to any such data and, therefore, the issue is not of central relevance to the outcome of the final rule. Therefore, the EPA is denying the request for reconsideration.

Issue: Establish work practice for other organic HAP instead of using CO as a surrogate.

The petitioners (AMP, JELD–WEN) requested that the EPA adopt a work practice standard for organic HAP rather than a numeric emissions limit based on CO as a surrogate for organic HAP. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees that a work practice standard is appropriate for such HAP for the subcategories for which the EPA adopted a numeric CO limit in the final rule, the petitioners have not demonstrated that they lacked the opportunity to comment on this issue. The EPA proposed numeric CO limits rather than a work practice, and the petitioners had the opportunity to provide their views during the public comment period on the proposed rule regarding why it believed a work practice standard should instead be finalized. Therefore, the EPA is denying the petition for reconsideration.

Issue: Allow health based compliance alternatives for HCl, other acid gases and manganese.

The petitioners (AMP, AF&PA, AHFA, AISI, ACCCI, RPU, CIBO) requested that the EPA adopt a HBES for HCl and other acid gases as well as for manganese, pursuant to section 112(d)(4). The petitioners also requested that the EPA grant reconsideration on this issue to better address the comments and data submitted during the public comment period for the proposed rule. The EPA is denying the request for reconsideration of this issue. The EPA did not propose a HBES for any pollutants, but did solicit public comment on such standards, explaining its concerns regarding health-based standards, including the lack of available data on which to base such standards. 75 *FR* at 32030. The EPA received comments addressing those concerns and responded to them in the final rule. 76 *FR* at 15642. Therefore, the petitioners have not demonstrated that it lacked the opportunity to comment on this issue. Further, the EPA received no data during the public comment period for the proposed rule on which it could base a HBES for HCl, other acid gases or manganese. Therefore, the petitions do not provide substantial support to demonstrate that the final rule should be changed. For these reasons, the EPA is denying the petition for reconsideration.

Issue: Provide additional compliance alternatives according to Executive Order 13563 (additional subcategories and HBES).

The petitioner (AHFA) requested that the EPA provide additional compliance alternatives in the final rule pursuant to Executive Order 13563 (Improving Regulation and Regulatory Review), including HBES. The EPA is denying the request for reconsideration on this issue because it is not of central relevance. First, nothing in Executive Order 13563 affects the EPA's discretion to establish HBES under the CAA. Additionally, the petition does not provide any information to address our concerns regarding HBES or data to establish such standards.

Issue: Remove energy assessment requirements.

The petitioners (AHFA, AISI, ACCCI, API, NPRA, AIF, CIBO, AF&PA, U.S. Sugar) requested that the EPA remove from the final rule the requirement that existing sources conduct an energy assessment. The EPA is denying the request for reconsideration on this issue. The EPA proposed an energy assessment requirement as a beyond-the-floor standard, and petitioners commented on that proposal. The EPA addressed those comments in the final rule, and petitioners have not demonstrated that they lacked the opportunity to comment on whether the EPA should require an energy assessment, including the EPA's legal authority to do so. 76 *FR* at 15631. Therefore, the EPA is denying the petition for reconsideration. The EPA continues to believe that an energy assessment is not only authorized by the CAA but required as a cost-effective beyond-the-floor standard in accordance with section 112(d)(2).

Issue: Require energy assessment to be conducted every 5 years.

The petitioner (Washington Dept. of Ecology) requested that the EPA require more frequent energy assessments. The EPA proposed a one-time assessment (75 *FR* at p. 32036) and the petitioner has not demonstrated it lacked the opportunity to comment on the frequency of the assessment requirement. Therefore, the EPA is denying the petition.

Issue: Modify cost analysis to include potential fuel savings from implementing assessment findings.

The petitioners (AIE, USCHPA) requested that the EPA modify its cost impacts analysis to include potential fuel savings from implementing energy assessment findings. The EPA is denying the petition. The impacts analysis, including specific mention of how cost savings for energy assessments were handled quantitatively, was explained in the proposal (see 75 FR 32026), and the petitioner therefore had the opportunity to comment on this issue. For this reason, the EPA is denying the petition for reconsideration on this issue.

Issue: Reconsider definition of ''cost effective.''

The petitioners (AIE, USCHPA) requested that the EPA reconsider the definition of ''cost-effective'' in the final rule. The EPA is denying the request for reconsideration on this issue. The EPA proposed to define cost-effective energy conservation measures as any measure with return of investment period of two years or less. 75 *FR* at 32036. The petitioners have not demonstrated it lacked the opportunity to comment on the proposed definition. Therefore, the EPA is denying the petition for reconsideration.

Issue: Establish work practice for other organic HAP instead of using CO surrogate.

The petitioners (AMP, JELD–WEN) requested that the EPA establish work practice standards for controlling organic HAP instead of using CO as a surrogate for organic HAP and establishing CO emission limits. The EPA is denying the request for reconsideration on this issue. Use of CO as a surrogate for organic HAP was subject to notice and comment. (75 FR 32018, 75 FR 32041). Responses to comment on this topic were provided in RTC document, Volume 2, EPA–HQ–OAR–2002–0058–3289, see section ''Choice of Regulated Pollutants: THC vs. CO vs. Other Organic HAP''.

Issue: Provide alternative format for units of measure for CO emission limits to allow sources to use their existing monitoring equipment.

The petitioners (UARG, CIBO) requested that the EPA provide an alternative format (ppm at X percent CO_2) for units of measure for CO emissions in addition to ppm at 3 percent oxygen. The EPA is denying the petition because the petitioners do not demonstrate that it was impracticable to comment on this issue. The format for units of measure for the limits was provided in the proposed rule, and petitioners could have commented on whether the proposed units were appropriate.

Issue: New source emission limits are unachievable and the EPA should collect additional fuel variability data from top performing units to adjust the limits.

The petitioner (AF&PA) requested that the EPA adjust the emissions limits for new sources by collecting additional data from the best performing units that they believed would result in increased variability. The petitioners have not demonstrated that they lacked the opportunity to comment. We proposed standards based on the data we had, including data collected during the ICR process in which petitioners participated, and that data were available for public review. Therefore, petitioners could have commented on this issue. Second, the CAA requires that we base the standards on the sources for which we have emissions information. Petitioners are always free to provide more information to us and the EPA specifically requested new data at each stage of the rulemaking to support the development of emission limits for each subcategory. (75 FR 32041, 76 FR 28663, 76 FR 80612). The EPA has incorporated revised data corrections or new data submittals in its analysis for the final rule. The EPA is denying the request for reconsideration.

Issue: Adjust the methodology for computing MACT floors to address statistical errors and variability concerns.

The petitioners (AISI, ACCCI, AF&PA) requested that the EPA adjust the methodology for computing MACT floors to address statistical errors and variability concerns, including: (1) Dataset reflects the ''best of the best'' units; (2) misapplication of statistical formulae to address distribution, confidence limits, and variability; and (3) failure to address variability in emissions from one unit over time. The methods used to compute the MACT floors were subject to notice and comment. Where new data or data corrections have been submitted that might alter data distributions, identifying best performers or application of fuel variability factors, these changes have been made in the final rule, but the general methodology remains the same. See *Solite Corp.* v. *EPA,* 952 F.2d 473, 485 (D.C. Cir. 1991) (public had sufficient notice of final rule threshold calculations where methodology did not change significantly from proposed rule). The EPA explained the MACT floor methodology in the proposed rule, and addressed comments received on the proposed methodology in the final rule (75 FR 32019–26, 32027–29, 76 15621–30, 76 FR 80614). Therefore, the EPA is denying the request for reconsideration.

Issue: Modify the basis for ranking the top performing units.

The petitioner (WEPCO) requested that the EPA modify the basis for ranking the top performing units, especially for new units, according to the average performance of the unit. The EPA is denying the petition. The methods used to rank units to establish the MACT floors were subject to notice and comment. The EPA explained its methodology in the proposed rule and addressed comments received on the ranking of data for computing the MACT floor in the final rule (75 FR 32019–26, 32027–29, 76 FR 15627).

Issue: Do not use a pollutant-by-pollutant approach to establish MACT floors.

The petitioners (AISI, ACCCI, AF&PA) requested that the EPA not use a pollutant-by-pollutant approach to establish MACT floors. The petitioners stated that this method is not a reasonable interpretation of Section 112(d)(3) of the CAA and that MACT floors should reflect levels achieved in practice, not aspirational controls. The EPA is denying the petition for reconsideration on this issue because it does not demonstrate that it was impracticable to comment on the issue. The EPA proposed MACT floors based on the pollutant-by-pollutant methodology, and therefore petitioners could, and in fact did, provide comments opposing this approach. See 75 FR 32021, 32029. The EPA addressed comments received on this approach in the final rule (76 FR 15621–23). Therefore, the EPA is denying the petition.

Issue: Revise approach to establish MACT floors where there is non-detect data.

The petitioner (Sierra Club) requested that the EPA not use the approach it used in the final rule based on the representative detection level (RDL) to establish MACT floors because it does not reflect actual emissions of any source within the subcategory. Further, the petitioner questioned the basis of the selected detection level, and whether or not other variability adjustments (e.g., UPL analysis) sufficiently account for measurement imprecision. The EPA is denying the petition. The three times representative detection level approach was subject to notice and comment. The EPA explained its rationale for this approach in the proposed rule (75 FR 32021) and responded to comments received in the final rule (76 FR 15623, 76 FR 80611).

Issue: The approach used to set MACT floor limits for dioxin/furan emissions is flawed and the EPA should establish an isomer-specific approach.

The petitioner (WEPCO) requested that the EPA establish an isomer-specific approach for dioxin/furan emissions because the three times detection level approach for dioxin/furan emissions is flawed. The EPA is denying the petition. This approach was subject to notice and comment. Rationale and responses to comments on this approach were provided at (75 FR 32021, 32041, 76 FR 15623). Further, the methods for establishing a representative detection level for dioxin/furan have been revised to account for the sensitivity of individual isomers, see rationale provided at (76 FR 80606).

Issue: Incorporate a fuel variability factor for PM based on the ash content of the fuel used by best performing units.

The petitioners (WEPCO, CIBO) requested that the EPA incorporate a fuel variability factor for PM based on the ash content of the fuel used by best performing units. The MACT floor methodology was explained in the June 4, 2010 proposal which included fuel variability factors that did not reflect the ash content of the fuel. Therefore, the petitioner could have commented recommending that the EPA do so, and, in fact, comments were provided on this issue. The EPA is denying the petition for reconsideration on this issue because it does not demonstrate that it was impracticable to comment on the issue. Responses to comment on this topic were provided in RTC document, Volume 1, EPA–HQ–OAR–2002–0058–3289, see section ''MACT Floor Methodology: Fuel Analysis Variability''.

Issue: Allow energy assessors to determine the time needed to conduct assessment.

The petitioner (Washington Dept. of Ecology) requested that the EPA allow the energy assessor to determine the time needed to conduct the energy assessment. The EPA is denying the petition. The duration of energy assessments was subject to notice and comment and the duration remains up to the affected source. Specific concerns with maximum duration requirements included in the March 21, 2011 final rule were clarified in the December 23, 2011 proposed notice of reconsideration. (76 FR 80615)

Issue: The unit designed to burn gas 1 subcategory should allow for limited use of liquid fuels.

The petitioners (ACC, CEG, API, NPRA) requested that the EPA allow units in the Gas 1 subcategory for limited use of liquid fuels; for example, units with a federally enforceable permit on back up fuels or units burning 10 percent or less of its heat input from liquid fuels should qualify as gas 1 units. The EPA is denying the petition because it does not demonstrate that it was impracticable to comment on the issue. The EPA proposed definitions of the various subcategories, and petitioners had the opportunity to comment on those definitions, including the proposed definition of the Gas 1 subcategory which did allow for the limited use of liquid fuels. The EPA addressed comments received on this issue in the final rule (76 FR 15620).

Issue: The unit designed to burn gas 1 subcategory should automatically include other gaseous fuels such as petrochemical process gas and landfill gas.

The petitioners (ACC, AIF, WM) requested that the EPA redefine the unit designed to burn gas 1 subcategory to automatically include other gaseous fuels such as petrochemical process gas and LFG, especially when the LFG is routed to a treatment system prior to use or sale. The EPA proposed definitions of units designed to burn gas 1 and units designed to burn gas 2 (other), and therefore the petitioner had the opportunity to comment on these definitions and to recommend that other gases be included in the definition of the Gas 1 subcategory (75 FR 32017, 32065). The EPA addressed comments received on this issue in the final rule (76 FR 15638). Therefore, the EPA is denying the petition.

Issue: Reconsider the emission standards established for the unit designed to burn gas 2 subcategory.

Petitioners (AIF, CIBO, WM, CEG) requested that the EPA reconsider the emission standards for the unit designed to burn gas 2 subcategory in light of what they feel was a limited dataset and lack of data from a diverse set of fuel types. The EPA is denying the petition. The MACT floor methodology was open to notice and comment in the June 4, 2010 proposal. The EPA proposed emissions standards for this subcategory and the petitioners had an opportunity to comment on the proposed standards and the data on which the standards were based. The EPA further notes that the CAA requires that the MACT standards be based on the best performing sources for which the Administrator has emissions information.

Issue: Adjust the ''metal process furnaces'' subcategory definition to include any gas-fired process furnace.

The petitioners (AISI, ACCCI) requested that the EPA adjust the ''metal process furnaces'' subcategory definition to include any gas-fired process furnace. The EPA is denying the petition. The definition of the subcategory for metal process furnaces was subject to notice and comment. (75 FR 32064, 76 FR 15620).

Issue: The designed to burn rationale for subcategorization is arbitrary.

The petitioner (Sierra Club) alleged that the designed to burn rationale for subcategorization is arbitrary, especially considering the large number of co-fired units in the inventory. The EPA proposed subcategories based on boiler design, and the petitioner has not demonstrated that it was impracticable to comment on the issue. In fact, the petitioner did submit comments on the proposed rule opposing the EPA's proposed subcategorization approach. Therefore, the EPA is denying the petition.

Issue: The EPA should consider exempting units from NSR.

The petitioners (MSU, PSU, Purdue, Citizens Thermal Energy) requested that the EPA consider exempting units from NSR who switch fuels, install pollution controls, or construct energy efficiency projects to meet the requirements of this rule because complying with the rule requirements will trigger NSR. The EPA is denying the petition. The applicability of NSR is outside the scope of this rulemaking. Moreover, it was not impracticable to comment on this issue during the 2011 rulemaking, in fact, comments were submitted on this issue, to which the EPA responded. See RTC document, Volume 2, EPA–HQ–OAR–2002–0058–3289, DCN EPA–HQ–OAR–2002–0058–2729.1, excerpt 17.

Issue: Remove the 10 percent penalty for sources opting to use the emission averaging compliance alternative.

The petitioners (AMP, MSU, PSU, Purdue, RPU, U.S. Sugar, Citizens Thermal Energy) requested that the EPA remove the 10 percent penalty for sources opting to use the emission averaging compliance alternative. The EPA is denying the petition. The EPA proposed an emissions averaging approach that included the 10 percent adjustment factor. (75 FR 32035) Therefore, the petition does not demonstrate that it was impracticable to comment on this issue. Responses to comment on this topic were provided in RTC document, Volume 2, EPA–HQ–OAR–2002–0058–3289, see section ''Emissions Averaging.''

Issue: Allow emissions averaging across subcategories.

The petitioners (MSU, PSU, Purdue, RPU, Citizens Thermal Energy) requested that the EPA allow emissions averaging across subcategories. The EPA is denying the petition. The EPA proposed an emissions averaging approach that did not allow averaging across subcategories, and petitioners therefore had the opportunity to comment recommending that the EPA allow such averaging. Responses to comment on this topic were provided in RTC document, Volume 2, EPA–HQ–OAR–2002–0058–3289, DCN EPA–HQ–OAR–2002–0058–3213.1, excerpt 175.

Issue: Allow a source's actual heat input instead of the maximum design heat input to be used in the emissions averaging provisions.

The petitioner (CIBO) requested that the EPA allow a source's actual heat input instead of the maximum design heat input to be used in the emissions averaging provisions of the final rule. The EPA proposed an emissions averaging approach that was based on the maximum rated heat input capacity, and petitioners therefore had the opportunity to comment recommending that the EPA base the averaging on actual heat input. Therefore, the EPA is denying the petition.

Issue: Reduce stack testing frequency to once every five years to reduce burden on facilities.

The petitioners (ACC, CIBO, JELD–WEN) requested that the EPA reduce stack testing frequency to once every 5 years and rely on the extensive set of continuous parameter monitoring in order to reduce burden on facilities. The EPA is denying the petition. The EPA proposed to require stack testing every year. The petition does not demonstrate that it was impracticable to comment on this issue, and the petitioners could have submitted comments requesting less frequent stack testing.

Issue: Incorporate detailed fuel sampling procedures using incorporation by reference mechanisms instead of detailing sampling procedures in the regulatory language.

The petitioner (CIBO) requested that the EPA incorporate detailed fuel sampling procedures using incorporation by reference mechanisms and citing credible literature (e.g., American Society for Testing and Materials) instead of detailing sampling procedures in the regulatory language since sampling procedures are subject to change over time. The EPA is denying the petition because the petitioner has not demonstrated that it was impracticable to comment on this issue. The EPA proposed fuel sampling procedures in the regulatory text in the June 4, 2010 proposal, and the petitioner therefore had the opportunity to comment recommending its preferred approach.

Issue: Remove the advanced submittal requirement for site-specific fuel monitoring plans before each analysis.

The petitioner (UARG) requested that the EPA remove the advanced submittal requirement for site-specific fuel monitoring plans before each analysis, especially if monthly frequency is maintained. If the fuel monitoring plan requirement remains, the petitioner requests that the EPA remove the requirement to report things that might change, such as unanticipated fuel use (based on unanticipated fuel changes). The EPA is denying the petition and disagrees with the commenter. First, the EPA proposed a fuel monitoring plan, and petitioners had the opportunity to comment on the plan requirement. The final rule requires submittal of a fuel monitoring plan 60 days before demonstrating initial compliance. The rule does not require re-submittal of this plan before each monthly analysis, see 40 CFR section 63.7521(b)(1).

Issue: Allow EPA Method 5B to demonstrate compliance with PM emission limits.

The petitioner (UARG) requested that the EPA allow EPA Method 5B to demonstrate compliance with PM emission limits. The EPA is denying the petition because it does not demonstrate that it was impracticable to comment on this issue. The EPA proposed methods to demonstrate compliance in the June 4, 2010 proposal and did not propose to allow Method 5B for PM compliance demonstrations. Therefore, the petitioner had the opportunity to submit comments recommending that the EPA allow the use of this method. For this reason, the EPA is denying the petition on this issue.

Issue: Remove or make references to Methods 2, 2F, 2G and 4 optional.

The petitioner (UARG) requested that the EPA remove or make references to EPA Methods 2, 2F, 2G and 4 optional. The EPA is denying the petition because it does not demonstrate that it was impracticable to comment on this issue. The EPA proposed methods to demonstrate compliance in the June 4, 2010 proposal and did not propose to make EPA Methods 2, 2F, 2G and 4 optional. Therefore, the petitioner had the opportunity to submit comments recommending that the EPA make the use of these methods optional. For this reason, the EPA is denying the petition on this issue.

Issue: Allow sources to petition for alternative PM monitoring requirements based on source-specific limitations.

The petitioner (CEG) requested that the EPA allow sources to petition for alternative PM monitoring requirements based on source-specific limitations (e.g., common stacks with more than one subcategory). The EPA is denying this petition because it is not of central relevance to this rulemaking. The General Provisions at 40 CFR 63.8 allow sources to petition the EPA for alternative monitoring plans. Therefore, no such provision is needed in this final rule.

Issue: Allow sources with overlapping CEMS regulations to comply with existing QA/QC plans or 40 CFR part 75 Appendices A and B.

The petitioners (CIBO, CMI) requested that the EPA allow sources with overlapping CEMS regulations to comply with existing QA/QC plans or 40 CFR part 75 Appendices A and B. The EPA is denying this petition because it is not of central relevance to this rulemaking.

Issue: No justification or discussion was provided on why the EPA selected 12 hours as the averaging time period and also why the EPA selected block averages instead of rolling averages.

The petitioner (Sierra Club) alleges that the EPA provided no justification or discussion explaining why the EPA selected 12 hours as the averaging time period and why the EPA selected block averages instead of rolling averages for parameter monitor. The petitioner requested that the EPA clarify that the averaging times for continuous parameter monitoring should be the same as the averaging times during the most recent performance test. Averaging times were open to notice and comment in the June 4, 2010 proposal. In the June 2010 proposal, we required that parameters be set based on 4-hour block averages during the compliance test, and that continuous compliance be demonstrated by monitoring 12-hour block average values for most parameters. We selected this averaging period to reflect operating conditions during the performance test to ensure the control system is continuously operating at the same or better level as during a performance test demonstrating compliance with the emission limits. Therefore, the EPA is denying the petition.

Issue: The EPA position regarding treatment of ''out-of-control'' and ''maintenance'' periods as deviations is not supported or explained.

The petitioner (UARG) alleges that the EPA position regarding treatment of ''out-of-control'' and ''maintenance'' periods as deviations is not supported or explained. The petitioner requested that the EPA revise the definition of ''deviation'' to be consistent with how deviation is treated with respect to CO CEMS and CPMS. The EPA is denying the petition. The definition of deviations was open to notice and comment in the June 4, 2010 proposal.

Issue: Require checks of pressure monitoring taps only if reading is abnormal.

The petitioner (CMI) requested that the EPA require checks of pressure monitoring taps only if reading is abnormal. The requirement to check pressure tap pluggage daily was open to notice and comment in the June 2010 proposal. In addition, the EPA is denying this petition because it is not of central relevance to this rulemaking.

Issue: The EPA has not sufficiently correlated emission limits to operating parameters and should not set enforceable limits on maximum and minimum control device operating parameters.

The petitioners (UARG, AMP, CIBO) alleges that the EPA has not sufficiently correlated emission limits to operating parameters and requested the EPA not to set enforceable limits on maximum and minimum control device operating parameters. One petitioner (CIBO) requested that the rule should allow sources to set their own ESP secondary voltage requirement based on load and coal quality since power consumption by an ESP is influenced by factors other than operating load, including ESP design, amount of PM collected, and resistivity of the PM. Other petitioners (UARG and AMP) also indicate that the limits set on control devices inhibit the flexibility to operate control devices with a margin of safety. The EPA is denying the petition. Operating limits were open to notice and comment in the June 4, 2010 proposal.

Issue: The EPA should delay incorporating PS 17 in this rule until the revisions for PS 17 are completed.

The petitioner (UARG) requested that the EPA delay incorporating PS 17 in this rule, which outlines how to select and install CPMS, until the revisions for PS 17 are completed.

The EPA is denying this petition. The final rule did not incorporate PS 17, or any other PS, in the provision regarding selection and installation of CPMS and ongoing quality assurance of data from CPMS. Comments related to revising PS 17 are outside the scope of this rulemaking. (RTC document, Chapter 11, EPA–HQ–OAR–2002–0058–3289, DCN EPA–HQ–OAR–2002–0058–2960.1, excerpt 150).

Issue: The EPA should not set an enforceable operating limit on opacity.

The petitioner (UARG) alleged that there is insufficient correlation between opacity and PM emissions and requested that the EPA not set an enforceable operating limit on opacity. The EPA is denying the petition. The EPA proposed opacity limits in the June 4, 2010 proposal and the petitioner therefore had the opportunity to comment on the proposed limits, including comments requesting that no limit be established.

Issue: Update outdated BLDS Guidance.

The petitioner (UARG) requested that the EPA update the outdated BLDS Guidance that is currently incorporated by reference. The EPA is denying this petition. The current guidance document is the most recent guidance available and comments related to revising the guidance document are outside the scope of this rulemaking. (RTC document, Chapter 11, EPA–HQ–OAR–2002–0058–3289, DCN EPA–HQ–OAR–2002–0058–2997.1, excerpt 10).

Issue: The EPA should reconsider emission limits for HCl on coal-fired boilers using a hot-side ESP for particulate control.

The petitioners (MSU, PSU, Purdue, Citizens Thermal Energy) requested that the EPA reconsider emission limits for HCl on coal-fired boilers using a hot-side ESP for particulate control. The petitioners are unaware of any HCl control devices that are compatible with a hot-side ESP. The EPA is denying the petition. The basis for subcategorization was subject to notice and comment. The EPA did not propose a separate subcategory for such units, and the petitioner could have commented recommending that the agency do so. (75 FR 32012, 76 FR 15617–18, 76 FR 80607) Further, the EPA disagrees with the petitioner that the subcategories could be based on the level of controls installed on the unit.

Issue: The EPA should change electronic reporting requirements to avoid WebFIRE and ERT shortcomings.

The petitioner (UARG) requested that the EPA change the electronic reporting requirements to avoid WebFIRE and ERT shortcomings. The petitioner requested that to meet the EPA's obligations under the Paperwork Reduction Act the EPA specify each individual data item requested in the ERT. The petitioner also requests that the EPA explain how the ERT electronic signature mechanisms will meet the requirements of the Cross-Media Electronic Reporting Rule.

The EPA is denying the petition because it does not demonstrate that it was impracticable to comment on this issue. The EPA proposed to require the use of the ERT and WebFIRE, and the petitioner therefore had the opportunity to comment on any concerns with the proposed approach.

Issue: Eliminate gas curtailment notification requirements or adjust the frequency of these notifications to be consistent with the reporting requirements in the Title V program.

The petitioner (AIF) requested that the EPA eliminate the gas curtailment notification requirements or adjust the frequency of these notifications to be consistent with the semi-annual reporting requirements in the Title V program. The EPA is denying the petition. Reporting requirements were open to notice and comment in the June 4, 2010 proposal.

Issue: Allow facilities to become area or synthetic minor sources instead of installing controls.

The petitioner (GPSP) requested that the EPA allow facilities to become area or synthetic minor sources instead of installing controls. The EPA is denying the petition. Whether or not sources elect to become area or synthetic minor sources is not of central relevance to this rulemaking, as nothing in this rule affects whether or how a source can become a synthetic minor source (RTC document, EPA–HQ–OAR–2002–0058–3289, Volume 1, DCN EPA–HQ–OAR–2002–0058–3176.2, excerpt 4).

VI. Impacts of This Final Rule

A. What are the incremental air impacts?

Table 4 of this preamble illustrates, for each basic fuel subcategory, the total emissions reductions achieved by the final amended rule (i.e., the difference in emissions between a boiler or process heater controlled to the amended floor level of control and boilers or process heaters at the current baseline) for new and existing sources. Nationwide emissions of selected HAP (i.e., HCl, HF, mercury, metals, and VOC) will be reduced by 44,300 tpy. This is an incremental increase of 4,000 tpy in HAP reductions compared to the estimates in the March 2011 final rule. This increase is due mainly to changes in the inventory (336 units were added since the March 2011 inventory). Excluding the changes in the inventory, the amendments to the regulatory provisions themselves resulted in a decrease of 1,100 tpy of estimated reductions, part of this incremental reduction in HAP is contributed to edits to the baseline emission data received since the March 2011 final rule, as well as changes to the subcategories and emission limits as a result of this amended rule. The amendments to the final rule are expected to result in an additional 4,600 tpy of reductions in HCl emissions. The amendments are also expected to have a modest effect on mercury, estimated to range from a slight decrease of 0.12 tpy up to a slight increase of 0.96 tpy in emission reductions as a result of the changes to the regulatory requirements. Reductions in emissions of filterable PM will decrease by 18,500 tpy due to the final amended rule. Reductions in emissions of non-mercury metals (i.e., antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium) will decrease by 260 tpy. In addition, the amendments are estimated to result in an additional 50,100 tpy of reductions in SO_2 emissions. A discussion of the methodology used to estimate emissions, emissions reductions, and incremental emission reductions is presented in ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the docket.

TABLE 4—SUMMARY OF TOTAL EMISSIONS REDUCTIONS FOR THE FINAL AMENDED RULE

[tons/yr]

Source	Subcategory	HCl	PM	Non mercury metals [a]	Mercury [b]	VOC
Existing Units	Limited Use	1	2	0.42	2.1E–04	0.48
	Solid units	36,737	21,367	147	0.4 to 1.5	1,619
	Liquid units	2,143	9,434	2,315	0.9 to 1	620
	Non-Continental Liquid units	35	3	1	0.01 to 0.02	23
	Gas 1 (NG/RG) units	20	117	0.3	0.01	88
	Gas 1 Metallurgical Furnaces	0.4	3	0.02	0.001	27
	Gas 2 (other) units	4	8	0.06	3.8E–03 to 4.6E–03.	40
New Units	Solid units	0	351	5	0.02	0
	Liquid units	0	0	0	0	0
	Gas 1 units	0	0	0	0	0
	Gas 1 Metallurgical Furnaces	0	0	0	0	0
	Gas 2 (other) units	0	0	0	0	0

[a] Includes antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

[b] Mercury reductions are presented as a range due to adjustments on reported fractions and limits of detection. See memorandum entitled ''Revised (March 2012) Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source'' for a description of the two methods for estimating mercury reductions.

B. What are the incremental water and solid waste impacts?

The EPA estimated the additional water usage that would result from installing wet scrubbers to meet the amended emission limits for HCl would be 556 million gallons per year for existing sources compared to the current baseline. In addition to the increased water usage, an additional 160 million gallons per year of wastewater would be produced for existing sources. Only half of these incremental changes are due to changes in the regulatory provisions. The other half is due to changes in the number of identified existing units and projected new units. The annual costs of treating the additional wastewater are $1.2 million. These additional costs are accounted for in the incremental control cost estimates.

The EPA estimated the additional solid waste that would result due to the amendments to be 138,000 tpy, with nearly all due to changes in the regulatory provisions. Solid waste is generated from flyash and dust captured in PM and mercury controls as well as from spent carbon that is injected into exhaust streams or used to filter gas streams. The costs of handling the additional solid waste generated are $5.8 million. These costs are also accounted for in the incremental control costs estimates.

A discussion of the methodology used to estimate incremental impacts is presented in ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the docket.

C. What are the incremental energy impacts?

The EPA estimated that the March 2011 final rule would result in an increase of about 1.4 billion kWh/yr in national energy usage from the electricity required to operate control devices, such as wet scrubbers, electrostatic precipitators and fabric filters which are expected to be installed to meet the final rule. The amendments are expected to decrease energy usage by a net 143 million kWh/yr compared to the March 2011 rule. These reductions are driven by the regulatory provisions of these amendments. Additionally, the EPA expects these amendments will result in a decrease of 4.4 million MMBtu/yr in fuel savings, compared with the estimates in the March 2011 final rule.

D. What are the incremental cost impacts?

For these final amendments, we estimated the incremental difference between the national costs impacts for the final amended rule and the March 2011 final rule. First, we determined the control measures, work practices, and monitoring and testing requirements that would be required by boilers and process heaters located at major source facilities to comply with the final amended rule. To estimate the national cost impacts of the final amended rule for existing sources, we used the identical methodology used to estimate the cost impacts for the March 2011 final rule with one exception. In this revised analysis, it was assumed that several liquid fuel units that reported natural gas firing capability would switch to natural gas as a compliance option instead of installing add-on controls to demonstrate compliance with the emission limits. Thus, the only costs to these units would be the tune-up work practice costs. A discussion of the methodology used to estimate cost impacts is presented in ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the docket.

The resulting total national cost impact of the final amended rule is $4.7 billion in capital expenditures and $1.5 billion per year in total annual costs, considering fuel savings. The total capital expenditures are slightly lower than estimated for the March 2011 final rule, but the total annual costs are slightly higher than estimated for the March 2011 final rule. See 76 FR 15651. The total capital and annual costs include costs for control devices, work practices, testing and monitoring.

In order to determine the incremental cost impacts of the amended requirements and emission limits, we first estimated the cost impacts of the additional existing boilers and process heaters added to the Boiler MACT inventory database since promulgation of the March 2011 final rule and the revised number of new boilers and process heaters that could be potentially constructed. Since the March 2011 final rule, we became aware of 72 major source facilities that were not previously in the Boiler MACT inventory database. Adding the boilers and process heaters located at these newly identified major source facilities resulted in 73 additional coal-fired units, 32 additional biomass-fired units, 82 additional oil-fired units, and 149 additional gas-fired units. Our revised number of new boilers and process heaters included 82 additional biomass units, 1,728 additional gas 1 units and 13 fewer liquid units.

The resulting cost impact for these additional existing and new boilers and process heaters is $1.0 billion in capital expenditures and $0.31 billion per year in total annual costs, considering fuel savings.

Therefore, discounting the added costs for the additional boilers and process heaters included in the costs analysis, the estimated incremental cost impacts for these amended requirements on existing and new boilers and process heaters are $1.0 billion in capital expenditures and $0.13 billion per year in total annual costs less than the costs estimated in the March 2011 rule.

Table 5 of this preamble shows the total capital and annual cost impacts of the final amended rule for each subcategory. Costs include testing and monitoring costs, but not recordkeeping and reporting costs.

TABLE 5—SUMMARY OF TOTAL CAPITAL AND ANNUAL COSTS FOR NEW AND EXISTING SOURCES FOR THE FINAL AMENDED RULE

Source	Subcategory	Estimated/projected number of affected units	Capital costs (10^6 $)	Testing and monitoring annualized costs (10^6 $/yr)	Annualized cost (10^6 $/yr) (considering fuel savings)
Existing Units	Coal units	621	2,554	46	904
	Biomass units	502	405	29	109
	Heavy Liquid units	319	761	5.4	221
	Light Liquid units	615	712	4.2	166
	Non-Continental Liquid units	21	62	0.8	17
	Gas 1 (NG/RG) units	11,929	77	0.9	(295)

TABLE 5—SUMMARY OF TOTAL CAPITAL AND ANNUAL COSTS FOR NEW AND EXISTING SOURCES FOR THE FINAL AMENDED RULE—Continued

Source	Subcategory	Estimated/projected number of affected units	Capital costs (10^6 $)	Testing and monitoring annualized costs (10^6 $/yr)	Annualized cost (10^6 $/yr) (considering fuel savings)
	Gas 2 (other) units	129	138	2.3	58
Energy Assessment	ALL	1,700 (Facilities).	N/A	N/A	28
New Units	Coal units	0	0	0	0
	Biomass units	82	381	5.6	[a] 99
	Liquid units	0	0	0	0
	Gas 1 (NG/RG) units	1,762	11	0	[a] 5.1
	Gas 2 (other) units	0	0	0	0

[a] Total annualized costs for new units do not account for fuel savings since no fuel savings are estimated in the first year for new units.

Potential control device cost savings and increased recordkeeping and reporting costs associated with the emissions averaging provisions in the final rule are not accounted for in either the capital or annualized cost estimates.

A discussion of the methodology used to estimate cost impacts is presented in ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the docket.

E. What are the economic impacts?

The EPA analyzed the economic impacts of this final amended rule using the methodology that was discussed in the March 2011 final rule RIA and in the preamble to the March 2011 final rule. See FR 76 15651. The market impact results are very similar to the results presented in the March 2011 final rule and the RIA. The agency's economic model suggests the average national price increases for industrial sectors are less than 0.01 percent, while average annual domestic production may fall by less than 0.01 percent.

Because of higher domestic prices, imports slightly rise. The results for sales tests for small businesses were somewhat reduced than those calculated for the March 2011 final rule. For the sales tests using small companies identified in the Combustion Survey, the mean cost to receipts dropped from 4 percent in the RIA to 3 percent for this final amended rule and the median was 0.2 percent for the RIA and also 0.2 percent for this final amended rule. The number of parent companies with sales tests exceeding 3 percent dropped from 8 in the RIA to 5 for this final amended rule. There was no change in the results for small public entities. Median cost is still about $1.1 million and representative small major public entities would have cost-to-revenue ratios above 10 percent. The change in employment estimates between the RIA and the final amended rule is minimal. In the RIA for the March 2011 final rule, we estimated employment changes ranging between −3,100 to +6,500 employees, with a central estimate of +1,700. For this final amended rule we estimate employment changes ranging between −2,600 to +5,400 employees, with a central estimate of +1,400. These estimated annual employment changes compared to the baseline employment, and are for the time period for which the annualized cost applies (2015 to 2029).

F. What are the benefits of this final rule?

We calculated health benefits using the methodology described in the RIA prepared for the March 21, 2011 final rule. We incorporated the revised emission reductions estimated for this reconsideration final rule into the analysis. We were unable to estimate the benefits from reducing exposure to HAP and ozone, ecosystem impairment and visibility impairment, including reducing 180,000 tons of carbon monoxide, 39,000 tons of HCl, 500 tons of HF, 2,500 tons of other metals and 3,100 to 5,300 pounds of mercury. Please refer to the full description of the unquantified benefits as well as technical details of the analysis and its limitations and uncertainties in the final Boiler RIA (March 2011). These monetized benefits are approximately 23 percent higher than the March 2011 final rule benefits due to the increase in SO_2 emission reductions associated with the additional units affected by the rule and the revised HCl limit. We estimate the total monetized benefits of this final regulatory action to be $27 billion to $67 billion at a 3 percent discount rate and $25 to $61 billion at a 7 percent discount rate. All estimates are for the implementation year (2015) in 2008$. A summary of the monetized benefits estimates at discount rates of 3 percent and 7 percent is provided in Table 6 of this preamble. A summary of the avoided health incidences is provided in Table 7 of this preamble.

TABLE 6—SUMMARY OF THE MONETIZED BENEFITS ESTIMATES FOR THE FINAL BOILER MACT

[millions of 2008$] [a b]

Pollutant	Emissions reductions (tons)	Total monetized benefits (at 3% discount rate)	Total monetized benefits (at 7% discount rate)
$PM_{2.5}$-related benefits			
Direct $PM_{2.5}$	14,139	$1,200 to $2,900	$1,100 to $ $2,700
SO_2	572,000	$26,000 to $64,000	$24,000 to $61,000

TABLE 6—SUMMARY OF THE MONETIZED BENEFITS ESTIMATES FOR THE FINAL BOILER MACT—Continued

[millions of 2008$] [a] [b]

Pollutant	Emissions reductions (tons)	Total monetized benefits (at 3% discount rate)	Total monetized benefits (at 7% discount rate)
Total		$27,000 to $67,000	$25,000 to $61,000.

[a] All estimates are for the implementation year (2015), and are rounded to two significant figures so numbers may not sum across rows. All fine particles are assumed to have equivalent health effects because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Benefits from reducing hazardous air pollutants (HAP) are not included. These estimates do not include energy disbenefits valued at $24 million (using a 3 percent discount rate). These benefits reflect existing boilers and new boilers anticipated to come online by 2015.

[b] There are some slight differences in the emission reductions used in the RIA and those used in the air impacts section of this preamble due to some late changes in the data that were received after the RIA was completed. Refer to the memoranda ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' for a discussion of the differences.

TABLE 7—SUMMARY OF THE AVOIDED HEALTH INCIDENCES FOR THE FINAL BOILER MACT [a]

	Avoided health incidences
Premature Mortality	3,000–7,900
Morbidity	
Chronic Bronchitis	2,000
Acute Myocardial Infarction	5,000
Hospital Admissions, Respiratory	750
Hospital Admissions, Cardiovascular	1,600
Emergency Room Visits, Respiratory	3,000
Acute Bronchitis	4,600
Work Loss Days	390,000
Asthma Exacerbation	51,000
Minor Restricted Activity Days	2,300,000
Lower Respiratory Symptoms	55,000
Upper Respiratory Symptoms	41,000

[a] All estimates are for the implementation year (2015), and are rounded to two significant figures. All fine particles are assumed to have equivalent health effects because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Benefits from reducing HAP are not included. These benefits reflect existing boilers and new boilers anticipated to come online by 2015.

G. What are the incremental secondary air impacts?

For units adding controls to meet the amended emission limits, we anticipate very minor secondary air impacts. The combustion of fuel needed to generate additional electricity would yield slight increases in emissions, including NO_X, CO, PM and SO_2 and an increase in CO_2 emissions. Since NO_X and SO_2 are covered by capped emissions trading programs and methodological limitations prevent us from quantifying the change in CO and PM, we do not estimate an increase in secondary air impacts for this final rule from additional electricity demand. We do estimate greenhouse gas impacts, which result from increased electricity consumption, to be 859,200 tpy from existing units and 79,700 tpy from new units. This is 19,200 tpy less than the estimated greenhouse gas impacts associated with the March 2011 final rule.

VII. Statutory and Executive Order Reviews

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

Under section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities. Accordingly, the EPA submitted this action to the OMB for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to the OMB recommendations have been documented in the docket for this action.

The EPA did prepare a new RIA for this action. The EPA prepared an assessment of the changes in the costs and benefits of this final rule compared to the costs and benefits associated with the March 21, 2011, final rule. Overall, the costs and impacts are estimated to be similar to the costs and impacts associated with the previous final rule, although the distribution is somewhat different and the number of affected units in the inventory has increased by about 302 units. When comparing the costs using only those sources that were part of the final rule inventory, the costs have decreased. The EPA re-ran the multimarket model to assess changes in economic impacts, and this analysis confirmed that the overall economic impacts are similar to the previous final rule. The benefits are projected to increase by about 20 percent because of the increase in the estimated SO_2 reductions. A summary of the costs and benefits of the previous final rule is provided in the preamble to the previous final rule (*see* 76 FR 15658) and the detailed analysis for the previous final rule is provided in the RIA for the previous final rule. In addition, memoranda are provided in the docket to document the changes in costs, economic impacts, and benefits associated with this final rule, shown in Table 8.

TABLE 8—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL BOILER MACT RECONSIDERATION IN 2015

[Millions of 2008$] [1]

	3 percent discount rate	7 percent discount rate
Total Monetized Benefits [2]	$27,000 to $67,000	$24,000 to $61,000.
Total Social Costs [3]	$1,400 to $1,600	$1,400 to $1,600.
Net Benefits	$26,000 to $65,000	$23,200 to $59,000.

TABLE 8—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL BOILER MACT RECONSIDERATION IN 2015—Continued

[Millions of 2008$] [1]

	3 percent discount rate	7 percent discount rate
Non-monetized Benefits	Health effects from exposure to HAP (39,000 tons of HCl, 500 tons of HF, 3,100 to 5,300 pounds of mercury, and 2,500 tons of other metals). Health effects from exposure to other criteria pollutants (180,000 tons of CO and 572,000 tons of SO_2). Ecosystem effects. Visibility impairment.	

[1] All estimates are for the implementation year (2015), and are rounded to two significant figures.

[2] The total monetized co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors such as directly emitted particles, SO_2, and NO_X and reducing exposure to ozone through reductions of VOC. It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Monetized benefits are shown as a range from Pope et al. (2002) to Laden et al. (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to support the development of differential effects estimates by particle type. These estimates include the energy disbenefits valued at $24 million (using the 3 percent discount rate), which do not change the rounded totals. CO_2-related disbenefits were calculated using the ''social cost of carbon'', which is discussed further in the RIA.

[3] The methodology used to estimate social costs for one year in the multimarket model using surplus changes results in the same social costs for both discount rates.

B. Paperwork Reduction Act

The OMB has approved the information collection requirements contained in the March 21, 2011 final rule under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0551. The EPA has updated the supporting statement to reflect the final inventory and burden estimates associated with this action since some of the monitoring, recordkeeping and reporting requirements have changed since the March 21, 2011 final rule. These revised estimates have been sent to OMB for review and approval.

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

This final rule will require maintenance inspections of the control devices but will not require any notifications or reports beyond those required by the General Provisions aside from a notification of intent to commence burning solid waste materials and notification of alternative fuel use for those units that are in the Gas 1 subcategory but burn liquid fuels for periodic testing, or during periods of gas curtailment or gas supply emergencies. The recordkeeping requirements require only the specific information needed to determine compliance.

The revised annual monitoring, reporting and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $95.3 million which is about the same as estimated for the March 2011 final rule. This includes 323,130 labor hours per year at a total labor cost of $30.6 million per year, and total non-labor capital costs of $64.7 million per year. This estimate includes initial and annual performance test, conducting and documenting an energy assessment, conducting fuel specifications for Gas 1 units, repeat testing under worst-case conditions for solid fuel units, conducting and documenting a tune-up, semiannual excess emission reports, maintenance inspections, developing a monitoring plan, notifications and recordkeeping. Monitoring, testing, tune-up and energy assessment costs and cost were also included in the cost estimates presented in the control costs impacts estimates in section VI.D of this preamble. The total burden for the federal government (averaged over the first 3 years after the effective date of the standard) is estimated to be 100,608 hours per year at a total labor cost of $5.3 million per year. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. In addition, the EPA is amending the table in 40 CFR part 9 of currently approved OMB control numbers for various regulations to list the regulatory citations for the information requirements contained in this final rule.

C. Regulatory Flexibility Act

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities.[1] The RFA also allows an agency to ''consider a series of closely related rules as one rule for the purposes of sections'' 603 (initial regulatory flexibility analysis) and 604 (final regulatory flexibility analysis) in order to avoid ''duplicative action.'' 5 U.S.C. § 605(c). This final rule is closely related to the final major source rule, which the EPA signed on February 21, 2011. The EPA prepared a final regulatory flexibility analyses in connection with the major source rule. Therefore,

[1] Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business according to Small Business Administration (SBA) size standards by the North American Industry Classification System category of the owning entity. The range of small business size standards for the affected industries ranges from 500 to 1,000 employees, except for petroleum refining and electric utilities. In these latter two industries, the size standard is 1,500 employees and a mass throughput of 75,000 barrels/day or less, and 4 million kilowatt-hours of production or less, respectively; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

pursuant to § 605(c), the EPA is not required to complete a final regulatory flexibility analysis for this rule.

The EPA has been concerned with potential small entity impacts since it began developing the major source rule. The EPA conducted outreach to small entities and, pursuant to § 609 of RFA, convened a Small Business Advocacy Review Panel to obtain advice and recommendations from small entity representatives.

Pursuant to the RFA, the EPA used the Panel's report and prepared both an initial regulatory flexibility analysis and a final regulatory flexibility analysis in connection with the closely related major source rule. Convening an additional Panel and preparing an additional final regulatory flexibility analysis would be procedurally duplicative and is unnecessary given that the issues here are within the scope of those considered by the Panel. In addition, this final action would decrease capital and annualized costs on small entities by about 3 percent and 10 percent, respectively, relative to the closely related final rule.

D. Unfunded Mandates Reform Act

Title II of the UMRA of 1995, 2 U.S.C. 1531–1538, requires federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on state, local and tribal governments and the private sector. Federal agencies must also develop a plan to provide notice to small governments that might be significantly or uniquely affected by any regulatory requirements. The plan must enable officials of affected small governments to have meaningful and timely input in the development of the EPA regulatory proposals with significant Federal intergovernmental mandates and must inform, educate, and advise small governments on compliance with the regulatory requirements.

Both this rule and the March 21, 2011 final rule contain a federal mandate that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or the private sector in any one year. Accordingly, the EPA prepared under section 202 of the UMRA a written statement for the final rule. This final rule also contains a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. The discussion below has been updated to reflect the changes.

1. Statutory Authority

As discussed in the March 21, 2011, final rule, the statutory authority for this final rulemaking is section 112 of the CAA. Title III of the CAA Amendments was enacted to reduce nationwide air toxic emissions. Section 112(b) of the CAA lists the 188 chemicals, compounds, or groups of chemicals deemed by Congress to be HAP. These toxic air pollutants are to be regulated by NESHAP.

Section 112(d) of the CAA directs us to develop NESHAP which require existing and new major sources to control emissions of HAP using MACT based standards. This NESHAP applies to all boilers and process heaters located at major sources of HAP emissions.

2. Social Costs and Benefits

The regulatory impact analysis prepared for the March 21, 2011 final rule, which we have revised for this final rule, including the agency's assessment of costs and benefits, is detailed in the ''Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011)'' and in the ''Regulatory Impact Results for the Reconsideration Final Rule for National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources'' in the docket. Based on estimated compliance costs associated with this final rule and the predicted change in prices and production in the affected industries, the estimated social costs of this rule are $1.4 to 1.6 billion (2008 dollars).

It is estimated that 3 years after implementation of this final rule, HAP would be reduced by 45,000 tpy, including reductions in HCl, hydrogen fluoride, metallic HAP including mercury, and several other organic HAP from boilers and process heaters. Studies have determined a relationship between exposure to these HAP and the onset of cancer, however, the agency is unable to provide a monetized estimate of the HAP benefits at this time. In addition, there are significant annual reductions in fine particulate matter ($PM_{2.5}$) and in SO_2 that would occur, including 25 thousand tons of $PM_{2.5}$ and 558 thousand tons of SO_2. These reductions occur within 3 years after the implementation of the final regulation and are expected to continue throughout the life of the affected sources. The major health effect associated with reducing $PM_{2.5}$ and $PM_{2.5}$ precursors (such as SO_2) are a reduction in premature mortality. Other health effects associated with $PM_{2.5}$ emission reductions include avoiding cases of chronic bronchitis, heart attacks, asthma attacks and work-lost days (i.e., days when employees are unable to work). While we are unable to monetize the benefits associated with the HAP emissions reductions, we are able to monetize the benefits associated with the $PM_{2.5}$ and SO_2 emissions reductions. For SO_2 and $PM_{2.5}$, we estimated the benefits associated with health effects of PM but were unable to quantify all categories of benefits (particularly those associated with ecosystem and visibility effects). Our estimates of the monetized benefits in 2015 associated with the implementation of the final regulatory action range from $27 billion (2008 dollars) to $67 billion (2008 dollars) when using a 3 percent discount rate (or from $25 billion (2008 dollars) to $61 billion (2008 dollars) when using a 7 percent discount rate). This estimate, at a 3 percent discount rate, is about $25 billion (2008 dollars) to $65 billion (2008 dollars) higher than the estimated social costs shown earlier in this section. The general approach used to value benefits is discussed in more detail earlier in this preamble. For more detailed information on the benefits estimated for the rulemaking, refer to the RIA and the memos updating the impacts and benefits in the docket.

3. Future and Disproportionate Costs

The UMRA requires that we estimate, where accurate estimation is reasonably feasible, future compliance costs imposed by this final rule and any disproportionate budgetary effects. Our estimates of the future compliance costs of the rule are discussed previously in this preamble.

We do not believe that there will be any disproportionate budgetary effects of this final rule on any particular areas of the country, state or local governments, types of communities (e.g., urban, rural) or particular industry segments. See the results of the ''Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011).''

4. Effects on the National Economy

The UMRA requires that we estimate the effect of this final rule on the national economy. To the extent feasible, we must estimate the effect on productivity, economic growth, full employment, creation of productive jobs and international competitiveness of the U.S. goods and services, if we determine that accurate estimates are reasonably feasible and that such effect is relevant and material.

The nationwide economic impact of this final rule is presented in the

''Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011)'' and a memoranda that are included in the docket, entitled ''Regulatory Impact Results for the Reconsideration Final Rule for National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources which update the RIA analyses. This analysis provides estimates of the effect of this rule on some of the categories mentioned above. The results of the economic impact analysis are summarized previously in this preamble. The results show that there will be a small impact on prices and output, and little impact on communities that may be affected by this final rule. In addition, there should be little impact on energy markets (in this case, coal, natural gas, petroleum products and electricity). Hence, the potential impacts on the categories mentioned above should be small.

5. Consultation With Government Officials

The UMRA requires that we describe the extent of the agency's prior consultation with affected state, local and tribal officials, summarize the officials' comments or concerns, and summarize our response to those comments or concerns. In addition, section 203 of the UMRA requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a final rule. We consulted with state and local air pollution control officials during the development of the final rule. We have also held meetings on this final rule with many of the stakeholders from numerous individual companies, institutions, environmental groups, consultants and vendors, labor unions and other interested parties. We have added materials to the docket to document these meetings.

Consistent with section 205, the EPA has identified and considered a reasonable number of regulatory alternatives. Additional information on the costs and environmental impacts of these regulatory alternatives is presented in the docket.

The regulatory alternative upon which the emission limits in this final rule are based represents the MACT floors for all subcategories and, as a result, it is the least costly and least burdensome alternative.

This rule is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. While some small governments may have some sources affected by this final rule, the impacts are not expected to be significant. Therefore, this final rule is not subject to the requirements of section 203 of the UMRA.

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, as specified in Executive Order 13132. This final rule will not impose direct compliance costs on state or local governments, and will not preempt state law. Thus, Executive Order 13132 does not apply to this action.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effects on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

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

The EPA interprets Executive Order 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This action is not subject to EO 13045 because it is based solely on technology performance.

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

This action is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. For the March 21, 2011, final rule, we estimated a 0.05 percent price increase for the energy sector and a −0.02 percent percentage change in production. We estimated a 0.09 percent increase in energy imports. For more information on the estimated energy effects, please refer to the ''Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011).'' The analysis is available in the public docket. While we did not recreate the RIA for this final action, the energy impacts for existing sources decreased slightly, and the energy impacts for new source increased due to the increased number of new sources that is now projected. Overall, the projected energy use increased slightly but would not change the analysis that was conducted for the previous final rule. Therefore, we conclude that this final rule when implemented is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA, Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs the EPA to use VCS in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. NTTAA directs the EPA to provide Congress, through the OMB, explanations when the agency decides not to use available and applicable VCS.

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 VCS. 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

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

For the March 2011 final rule, the EPA determined that the rule would not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. Compared to the previous final rule, while the amendments are somewhat less stringent for some subcategories of units and more stringent for some others, the overall increased health benefits demonstrate that the conclusions from the environmental justice analysis conducted for the previous final rule are still valid. Therefore, the EPA has determined this final rule will not have disproportionately high and adverse human or environmental effects on minority or low-income populations.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this final rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). With the exception of the May 18, 2011 (76 FR 28661), delay of the effective date revising subpart DDDDD at 76 FR 15451 (March 21, 2011) being lifted January 31, 2013, this rule will be effective April 1, 2013.

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and Recordkeeping requirements.

Dated: December 20, 2012

Lisa P. Jackson,

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—[AMENDED]

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

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

■ 2. Effective January 31, 2013, the May 18, 2011 (76 FR 28661), delay of the effective date revising subpart DDDDD at 76 FR 15451 (March 21, 2011) is lifted.

Subpart A—[Amended]

■ 3. Section 63.14 is amended by:
■ a. Revising paragraphs (b)(19), (b)(23), (b)(35), (b)(40), (b)(69), and (b)(70).
■ b. Removing and reserving paragraph (b)(53).
■ c. Adding paragraphs (b)(46), (b)(55), and (b)(76) through (83).
■ d. Adding paragraphs (p)(12) through (20).
■ e. Adding paragraph (r).

The revisions and additions read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(b) * * *

(19) ASTM D95–05 (Reapproved 2010), Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation, approved May 1, 2010, IBR approved for § 63.10005(i) and table 6 to subpart DDDDD.

* * * * *

(23) ASTM D4006–11, Standard Test Method for Water in Crude Oil by Distillation, including Annex A1 and Appendix X1, approved June 1, 2011, IBR approved for § 63.10005(i) and table 6 to subpart DDDDD.

* * * * *

(35) ASTM D6784–02 (Reapproved 2008) Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), approved April 1, 2008, IBR approved for table 1 to subpart DDDDD of this part, table 2 to subpart DDDDD of this part, table 5 to subpart DDDDD, table 11 to subpart DDDDD of this part, table 12 to subpart DDDDD of this part, table 13 to subpart DDDDD of this part, and table 4 to subpart JJJJJJ of this part.

* * * * *

(40) ASTM D396–10 Standard Specification for Fuel Oils, approved October 1, 2010, IBR approved for § 63.7575 and § 63.11237.

* * * * *

(46) ASTM D4606–03 (2007), Standard Test Method for Determination of Arsenic and Selenium in Coal by the Hydride Generation/Atomic Absorption Method, approved October 1, 2007, IBR approved for table 6 to subpart DDDDD.

* * * * *

(55) ASTM D6357–11, Test Methods for Determination of Trace Elements in Coal, Coke, and Combustion Residues from Coal Utilization Processes by Inductively Coupled Plasma Atomic Emission Spectrometry, approved April 1, 2011, IBR approved for table 6 to subpart DDDDD.

* * * * *

(69) ASTM D4057–06 (Reapproved 2011), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, including Annex A1, approved June 1, 2011, IBR approved for § 63.10005(i) and table 6 to subpart DDDDD.

(70) ASTM D4177–95 (Reapproved 2010), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, including Annexes A1 through A6 and Appendices X1 and X2, approved May 1, 2010, IBR approved for § 63.10005(i) and table 6 to subpart DDDDD.

* * * * *

(76) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, approved July 15, 2011, IBR approved for § 63.7575 and § 63.11237.

(77) ASTM D975–11b, Standard Specification for Diesel Fuel Oils, approved December 1, 2011, IBR approved for § 63.7575.

(78) ASTM D5864–11 Standard Test Method for Determining Aerobic Aquatic Biodegradation of Lubricants or Their Components, approved March 1, 2011, IBR approved for table 6 to subpart DDDDD.

(79) ASTM D240–09 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, approved July 1, 2009, IBR approved for table 6 to subpart DDDDD.

(80) ASTM D4208–02 (2007) Standard Test Method for Total Chlorine in Coal by the Oxygen Bomb Combustion/Ion Selective Electrode Method, approved May 1, 2007, IBR approved for table 6 to subpart DDDDD.

(81) ASTM D5192–09 Standard Practice for Collection of Coal Samples from Core, approved June 1, 2009, IBR approved for table 6 to subpart DDDDD.

(82) ASTM D7430–11ae1, Standard Practice for Mechanical Sampling of Coal, approved October 1, 2011, IBR approved for table 6 to subpart DDDDD.

(83) ASTM D6883–04, Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles, approved June 1, 2004, IBR approved for table 6 to subpart DDDDD.

* * * * *

(p) * * *

(12) Method 5050 (SW–846–5050), Bomb Preparation Method for Solid Waste, Revision 0, September 1994, in

EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition IBR approved for table 6 to subpart DDDDD.

(13) Method 9056 (SW–846–9056), Determination of Inorganic Anions by Ion Chromatography, Revision 1, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(14) Method 9076 (SW–846–9076), Test Method for Total Chlorine in New and Used Petroleum Products by Oxidative Combustion and Microcoulometry, Revision 0, September 1994, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(15) Method 1631 Revision E, Mercury in Water by Oxidation, Purge and Trap, and Cold Vapor Atomic Absorption Fluorescence Spectrometry, Revision E, EPA–821–R–02–019, August 2002, IBR approved for table 6 to subpart DDDDD.

(16) Method 200.8, Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma—Mass Spectrometry, Revision 5.4, 1994, IBR approved for table 6 to subpart DDDDD.

(17) Method 6020A (SW–846–6020A), Inductively Coupled Plasma-Mass Spectrometry, Revision 1, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(18) Method 6010C (SW–846–6010C), Inductively Coupled Plasma-Atomic Emission Spectrometry, Revision 3, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(19) Method 7060A (SW–846–7060A), Arsenic (Atomic Absorption, Furnace Technique), Revision 1, September 1994, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(20) Method 7740 (SW–846–7740), Selenium (Atomic Absorption, Furnace Technique), Revision 0, September 1986, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

* * * * *

(r) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Norcross, GA 30092, (800) 332–8686, *http://www.tappi.org*.

(1) TAPPI T 266, Determination of Sodium, Calcium, Copper, Iron, and Manganese in Pulp and Paper by Atomic Absorption Spectroscopy (Reaffirmation of T 266 om-02), Draft No. 2, July 2006, IBR approved for table 6 to subpart DDDDD.

(2) [Reserved]

Subpart DDDDD—[Amended]

■ 4. Section 63.7485 is revised to read as follows:

§ 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in § 63.7575 that is located at, or is part of, a major source of HAP, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.7575.

■ 5. Section 63.7490 is amended by adding paragraph (e) to read as follows:

§ 63.7490 What is the affected source of this subpart?

* * * * *

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

■ 6. Section 63.7491 is amended by:
■ a. Revising the introductory text.
■ b. Revising paragraph (a).
■ c. Revising paragraph (c).
■ d. Revising paragraph (h)
■ e. Revising paragraph (i).
■ f. Revising paragraph (m).
■ g. Revising paragraph (n).

The revisions read as follows:

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

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part.

* * * * *

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

* * * * *

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler or process heater is provided by regulated gas streams that are subject to another standard.

* * * * *

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in § 63.1200(b) is not covered by Subpart EEE.

(n) Residential boilers as defined in this subpart.

* * * * *

■ 7. Section 63.7495 is amended by:
■ a. Revising paragraph (a).
■ b. Revising paragraph (b).
■ c. Adding paragraphs (e), (f), and (g).

The revisions and additions 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 January 31, 2013, or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in § 63.6(i).

* * * * *

(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, 2013, 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.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in § 63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

■ 8.Section 63.7499 is amended by revising paragraphs (d) and (f) through (l) and adding paragraphs (p) through (u) to read as follows:

§ 63.7499 What are the subcategories of boilers and process heaters?

* * * * *

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

* * * * *

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

* * * * *

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

■ 9. Section 63.7500 is amended by:

■ a. Revising paragraph (a).

■ b. Revising paragraph (c).

■ c. Adding paragraph (d).

■ d. Adding paragraph (e).

■ e. Adding paragraph (f).

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

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

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 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 steam. 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 electricity. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (a)(1)(iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to this subpart until January 31, 2016.

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

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(3) At all times, you must operate and maintain any affected source (as defined in § 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

* * * * *

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in § 63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

(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 Table 3 to this subpart.

■ 10. Section 63.7501 is revised to read as follows:

§ 63.7501 Affirmative Defense for Violation of Emission Standards During Malfunction.

In response to an action to enforce the standards set forth in § 63.7500 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) *Assertion of affirmative defense.* To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design, or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when a violation occurred; and

(3) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in § 63.7500 of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

■ 11. Section 63.7505 is amended by:

■ a. Revising paragraph (a).

■ b. Revising paragraph (c).

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

§ 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 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), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance 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 (including 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).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in § 63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of § 63.7525. Using the process described in § 63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

* * * * *

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations, accuracy audits, analytical drift).

* * * * *

■ 12. Section 63.7510 is revised 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 testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to § 63.7520 and Table 5 to this subpart.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to

§ 63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

(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 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 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 fuels according to § 63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

(3) Establish operating limits according to § 63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to § 63.7525.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 13 to this subpart for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart. The fuels described in paragraph (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to § 63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 12, 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.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with § 63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration, 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, except as specified in paragraph (j) of this section.

(f) For new or reconstructed affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than July 29, 2016.

(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 § 63.7540(a) 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 § 63.7540(a).

(h) For affected sources (as defined in § 63.7490) that ceased burning solid waste consistent with § 63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2013, you must demonstrate compliance within 180 days after becoming an affected source.

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

■ 13. Section 63.7515 is revised to read as follows:

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

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 to this subpart).

(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 the initial startup of the new or reconstructed affected source.

(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.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.7550.

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

(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 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.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in § 63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in § 63.7510(a).

■ 14. Section § 63.7520 is amended by revising paragraphs (a), (c), (d), and (e) and adding paragraph (f) to read as follows:

§ 63.7520 What stack tests and procedures must I use?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

* * * * *

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A–7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

(f) Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

■ 15. Section 63.7521 is revised to read as follows:

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

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section and Table 6 to this subpart.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in § 63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

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

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(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.

(c) At a minimum, you must obtain three 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.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(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. For monthly sampling, each composite sample shall be collected at approximately equal 10-day intervals during the month.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in

Table 6 to this subpart, for use in Equations 7, 8, and 9 of this subpart.

(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.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

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

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

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

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(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.

(h) You must obtain a single fuel sample for each fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

■ 16. Section § 63.7522 is revised by:
■ a. Revising paragraphs (a) through (d).
■ b. Revising paragraphs (e)(1) and (2).
■ c. Revising paragraphs (f) introductory text and (f)(1) and (2).
■ d. Revising paragraphs (g) introductory text, (g)(2)(i), (g)(2)(iv), (g)(2)(vi)(B), (g)(3) introductory text, (g)(4) introductory text, and (g)(4)(ii).
■ e. Revising paragraph (h).
■ f. Revising paragraph (i).
■ g. Revising paragraph (j)(1).
■ h. Revising paragraph (k).

The revisions read as follows:

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

(a) As an alternative to meeting the requirements of § 63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

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

(1) You may average units using a CEMS or PM CPMS for demonstrating compliance.

(2) For mercury and HCl, averaging is allowed as follows:

(i) You may average among units in any of the solid fuel subcategories.

(ii) You may average among units in any of the liquid fuel subcategories.

(iii) You may average among units in a subcategory of units designed to burn gas 2 (other) fuels.

(iv) You may not average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn gas 2 (other) subcategories.

(3) For PM (or TSM), averaging is only allowed between units within each of the following subcategories and you may not average across subcategories:

(i) Units designed to burn coal/solid fossil fuel.

(ii) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(iii) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

(iv) Fluidized bed units designed to burn biomass/bio-based solid.

(v) Suspension burners designed to burn biomass/bio-based solid.

(vi) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(vii) Fuel Cells designed to burn biomass/bio-based solid.

(viii) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(ix) Units designed to burn heavy liquid fuel.

(x) Units designed to burn light liquid fuel.

(xi) Units designed to burn liquid fuel that are non-continental units.

(xii) Units designed to burn gas 2 (other) gases.

(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

January 31, 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 January 31, 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 operating following the compliance date specified in § 63.7495.

(e) * * *

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

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

Where:

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

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

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

1.1 = Required discount factor.

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

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

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

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

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

1.1 = Required discount factor.

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

Where:

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

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

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

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

1.1 = Required discount factor.

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

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

Where:

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

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

Sm = Maximum steam generation capacity by unit, i, in units of pounds per hour.
Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.
1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in § 63.7495. If the affected source elects to collect monthly data for up the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of this section.

(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 steam generation for the month if you are complying with the emission limits on a electrical generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Hb\right) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3a)}$$

Where:
AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input, for that calendar month.
Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.
Hb = The heat input for that calendar month to unit, i, in units of million Btu.
n = Number of units participating in the emissions averaging option.
1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times So\right) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 3b)}$$

Where:
AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.
Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to § 63.7533 for that unit.
So = The steam output for that calendar month from unit, i, in units of million Btu, as defined in § 63.7575.
n = Number of units participating in the emissions averaging option.
1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Eo\right) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq. 3c)}$$

Where:
AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.
Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to § 63.7533 for that unit.
Eo = The electric generating output for that calendar month from unit, i, in units of megawatt hour, as defined in § 63.7575.
n = Number of units participating in the emissions averaging option.
1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3a of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left(Er \times Sa \times Cfi\right) \div \sum_{i=1}^{n} \left(Sa \times Cfi\right) \qquad \text{(Eq. 4)}$$

Where:
AveWeightedEmissions = average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million

Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.

1.1 = Required discount factor.

* * * * *

(g) You must develop, and submit upon request to the applicable Administrator for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

* * * * *

(2) * * *

(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of January 31, 2013 and the date on which you are requesting emission averaging to commence;

* * * * *

(iv) The test plan for the measurement of PM (or TSM), HCl, or mercury emissions in accordance with the requirements in § 63.7520;

* * * * *

(vi) * * *

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the Administrator, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

* * * * *

(3) The Administrator shall review and approve or disapprove the plan according to the following criteria:

* * * * *

(4) The applicable Administrator shall not approve an emission averaging implementation plan containing any of the following provisions:

* * * * *

(ii) The inclusion of any emission source other than an existing unit in the same subcategories.

* * * * *

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

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

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

Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu), parts per million (ppm), or nanograms per dry standard cubic meter (ng/dscm).

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

Hi = Heat input from unit i, MMBtu.

* * * * *

(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategories subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

■ 17. Section 63.7525 is amended by:

■ a. Revising paragraph (a)

■ b. Revising paragraph (b).

■ c. Revising paragraph (c) introductory text.

■ d. Revising paragraphs (d) introductory text and paragraphs (d)(1) through (d)(4).

■ e. Revising paragraph (e)(2).

■ f. Revising paragraph (e)(3).

■ g. Revising paragraph (f)(2).

■ h. Revising paragraph (j).

■ i. Revising paragraph (k).

■ j. Adding paragraph (l).

■ k. Adding paragraph (m).

The revisions and additions 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 according to the procedures in paragraphs (a)(1) through (7) of this section.

(1) Install the CO CEMS and oxygen analyzer by the compliance date specified in § 63.7495. The CO and oxygen levels shall be monitored at the same location at the outlet of the boiler or process heater.

(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, 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.

(i) You must conduct a performance evaluation of each CO CEMS according to the requirements in § 63.8(e) and according to Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B.

(ii) During each relative accuracy test run of the CO CEMS, you must be collect emission data for CO concurrently (or within a 30- to 60-minute period) by both the CO CEMS and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A–4. The relative accuracy testing must be at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with § 63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Complete a minimum of one cycle of CO and oxygen CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen data concurrently. Collect at least four CO and oxygen 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.

(4) Reduce the CO CEMS data as specified in § 63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected 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.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

(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, certify, 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, 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, certify, 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.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable of detecting and responding to PM concentrations of no greater than 0.5 milligram per actual cubic meter.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d). Express the PM CPMS output as milliamps.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

(5) Install, certify, operate, and maintain your PM CEMS 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)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of § 60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A–3 or Method 17 at 40 CFR part 60, appendix A–6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/erttool.html/*).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the

initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in § 63.7495.

* * * * *

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.7495.

(1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in § 63.7535(b), and comply with the data calculation requirements specified in § 63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in § 63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in § 63.7535(c).

* * * * *

(e) * * *

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.

(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

* * * * *

(f) * * *

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

* * * * *

(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA–454/R–98–015 (incorporated by reference, see § 63.14).

(3) Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

(6) Where multiple bag leak detectors are required, the system's instrumentation and alert may be shared among detectors.

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date a final performance specification for a HCl CEMS is published in the **Federal Register** or the date of approval of a site-specific monitoring plan.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(14) for a mercury CEMS and § 63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A–7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM, mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide

(SO_2) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(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 use an SO_2 CEMS, 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 part 75 of this chapter.

(1) The SO_2 CEMS must be installed by the compliance date specified in § 63.7495.

(2) For on-going quality assurance (QA), the SO_2 CEMS must meet 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.

(3) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting SO_2 data, you must operate the SO_2 CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when SO_2 data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values.

■ 18. Section 63.7530 is amended by:
■ a. Revising paragraph (a).
■ b. Revising paragraph (b) introductory text.
■ c. Redesignating paragraph (b)(3) as paragraph (b)(4) and adding new paragraph (b)(3).
■ d. Revising newly designated paragraph (b)(4).
■ e. Revising paragraph (c), (c)(2) through (4).
■ f. Adding paragraph (c)(5).
■ g. Revising paragraphs (d), (e), (g), and (h).
■ h. Adding paragraph (i).

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)(i). 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 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).

* * * * *

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSMi).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

$$TSMinput = \sum_{i=1}^{n} \left(TSMi \times Qi \right) \qquad \text{(Eq. 9)}$$

Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSMi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of TSM. 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.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in § 63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, 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 operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(*1*) Your PM CPMS must provide a 4–20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(*2*) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(*3*) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(*1*) through (*4*) of this section.

(*1*) Determine your instrument zero output with one of the following procedures:

(*i*) Zero point data for *in-situ* instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*ii*) Zero point data for *extractive* instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*iii*) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (*e.g.,* when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*iv*) If none of the steps in paragraphs (b)(4)(ii)(B)(*1*)(*i*) through (*iii*) of this section are possible, you must use a zero output value provided by the manufacturer.

(*2*) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_1, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 10)}$$

Where:

X_1 = the PM CPMS data points for the three runs constituting the performance test,

Y_1 = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

(*3*) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 11)}$$

Where:

R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y_1 = the three run average lb/MMBtu PM concentration,

X_1 = the three run average milliamp output from you PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

(*4*) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu per milliamp value from Equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + \frac{0.75(L)}{R} \qquad \text{(Eq. 12)}$$

Where:

O_l = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = your source emission limit expressed in lb/MMBtu,

z = your instrument zero in milliamps, determined from (B)(i), and

R = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

(C) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your 30-day rolling average operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13 and you must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of this section.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \qquad \text{(Eq. 13)}$$

Where:

X_1 = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

(D) 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, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

$$30-\mathrm{day}=\frac{\sum_{i=1}^{n} Hpvi}{n} \qquad \text{(Eq. 14)}$$

Where:

30-day = 30-day average.

Hpvi = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 720 operating hours.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Tables 1, 2, or 11 through 13 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers (''back half'') of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the ''back half'' for other purposes.

(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.

(iii) 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.)

(iv) 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.

(v) 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.

(vi) 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.

(vii) 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.

(viii) 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) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to § 63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

* * * * *

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of this section.

$$P90 = mean + (SD \times t) \qquad \text{(Eq. 15)}$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile ($t_{0.1}$) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} \left(Ci90 \times Qi \times 1.028 \right) \qquad \text{(Eq. 16)}$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 11 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.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n} \left(Hgi90 \times Qi \right) \qquad \text{(Eq. 17)}$$

Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 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.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

$$Metals = \sum_{i=1}^{n} \left(TSM90i \times Qi \right) \qquad \text{(Eq. 18)}$$

Where:

Metals = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 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.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.

(d) If you own or operate an existing unit with a heat input capacity of less than 10 million Btu per hour or a unit in the unit designed to burn gas 1 subcategory, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the unit.

(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility at the time of the assessment.

* * * * *

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i) and according to the frequency listed in § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(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 item 5 of Table 3 of this subpart.

(i) If you opt to comply with the alternative SO_2 CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and SO_2 CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with § 63.7500(a)(3); and

(3) You establish a unit-specific maximum SO_2 operating limit by

collecting the minimum 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 most recent HCl performance test.

■ 19. Section 63.7533 is amended by:
■ a. Revising the section heading.
■ b. Revising paragraph (a).
■ c. Revising paragraphs (b)(1) and (4).
■ d. Revising paragraphs (c) introductory text, (c)(1)(i) and (ii), (c)(2)(i), and (c)(3).
■ e. Revising paragraph (d) through (f).
■ f. Adding paragraph (g).

The revisions and addition read as follows:

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

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

(b) * * *

(1) The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

* * * * *

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) * * *

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

* * * * *

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

$$ECredits = \left(\sum_{i=1}^{n} EIS_{iactual} \right) \div EI_{baseline} \qquad \text{(Eq. 19)}$$

Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.

(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 operating, following the compliance date specified in § 63.7495.

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

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

Where:

E_{adj} = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 for the affected boiler.

(g) As part of each compliance report submitted as required under § 63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.

■ 20. Section 63.7535 is amended by revising the section heading and paragraphs (b), (c), and (d) to read as follows:

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

* * * * *

(b) You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater is operating and compliance is required, except for periods of monitoring system malfunctions or out of control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during 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 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 annual report.

■ 21. Section 63.7540 is revised to read as follows:

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

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in § 63.7550(c), 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) Lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) 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 12 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.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 12 of § 63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the

procedures in § 63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in § 63.7510(a)(2)(i) through (iii).

(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 13 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.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 13 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 of § 63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). 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.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§ 63.7525(a) and 63.7535.

(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 operating.

(iii) Keep records of CO levels according to § 63.7555(b).

(iv) You must record and make available upon request results of CO CEMS performance audits, dates and duration of periods when the CO CEMS is out of control to completion of the corrective actions necessary to return the CO CEMS to operation consistent with your site-specific monitoring plan.

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

(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. 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 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;

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject;

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

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

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(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.

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(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 the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date a final performance specification for an HCl CEMS is published in the **Federal Register** or the date of approval of a site-specific monitoring plan.

(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 the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 9 of § 63.7530. If the results of recalculating the maximum TSM input using Equation 9 of § 63.7530 are higher than the maximum total selected input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). 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.

(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 14 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.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 14 of § 63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(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, updated at the end of each new boiler or process heater operating hour.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 13 of this subpart.

(i) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2— Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

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

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(vii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in § 63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in § 63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in § 63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in § 63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in § 63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

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

■ 22. Section 63.7541 is amended by revising paragraphs (a)(3) and (4) to read as follows:

§ 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

* * * * *

(a) * * *

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling

average parameter values consistent with the approved monitoring plan.

* * * * *

■ 23. Section 63.7545 is amended by:
■ a. Revising paragraphs (a) through (c).
■ b. Revising paragraphs (e) introductory text, (e)(1), (e)(2), (e)(3), (e)(4), (e)(5) introductory text, and (e)(5)(i).
■ c. Adding paragraph (e)(5)(ii).
■ d. Revising paragraphs (e)(8)(i) and (iii).
■ e. Revising paragraph (f) introductory text.
■ f. Revising paragraphs (g)(1) and (2).
■ g. Revising paragraphs (h) introductory text and (h)(1) and (3).
■ h. Removing paragraph (h)(4).

The revisions and addition read as follows:

§ 63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013.

(c) As specified in § 63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

* * * * *

(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), 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).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under § 241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of § 241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 13 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

* * * * *

(8) * * *

(i) ''This facility complies with the required initial tune-up according to the procedures in § 63.7540(a)(10)(i) through (vi).''

* * * * *

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: ''No secondary materials that are solid waste were combusted in any affected unit.''

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

* * * * *

(g) * * *

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories under this subpart.

* * * * *

(h) If you have switched fuels or made a physical change to the boiler 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:

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

* * * * *

(3) The date upon which the fuel switch or physical change occurred.

■ 24. Section 63.7550 is revised to read as follows:

§ 63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(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 an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or 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 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 July 31 or January 31, whichever date is the first date that occurs at least 180 days (or 1, 2, or 5 years, as applicable, if submitting an annual, biennial, or 5-year compliance report) after the compliance date that is specified for your source in § 63.7495.

(2) The first 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 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 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.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to a the requirements of a tune up they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv) and (xiv) of this section.

(2) If a facility is complying with the fuel analysis they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv), (vi), (x), (xi), (xiii), (xv) and paragraph (d) of this section.

(3) If a facility is complying with the applicable emissions limit with performance testing they must submit a compliance report with the information in (c)(5)(i) through (iv), (vi), (vii), (ix), (xi), (xiii), (xv) and paragraph (d) of this section.

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

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(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 12 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 13 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 14 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).

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 of § 63.7530, or the maximum TSM input operating limit using Equation 9 of § 63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§ 63.7521(f) and 63.7530(g).

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and mercury) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(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, 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 or operating limit from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) A brief description of the source for which there was a deviation.

(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f) [Reserved]

(g) [Reserved]

(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 (defined in § 63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart and the compliance reports required in § 63.7550(b) to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to the EPA via CDX as described earlier in this paragraph. At the discretion of the Administrator, you must also submit these reports, including the confidential business information, to the Administrator in the format specified by the Administrator. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator.

(2) Within 60 days after the date of completing each CEMS performance evaluation test (defined in 63.2) you must submit the relative accuracy test audit (RATA) data to the EPA's Central Data Exchange by using CEDRI as mentioned in paragraph (h)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator shall submit the results of the performance evaluation in paper submissions to the Administrator.

(3) You must submit all reports required by Table 9 of this subpart electronically using CEDRI that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due the report you must submit the report to the Administrator at the appropriate address listed in § 63.13. At the discretion of the Administrator, you must also submit these reports, to the Administrator in the format specified by the Administrator.

■ 25. Section 63.7555 is amended by:

■ a. Revising paragraphs (d) introductory text and (d)(2) through (6).

■ b. Adding paragraphs (d)(9) through (11).

■ c. Revising paragraphs (f) through (h).

■ d. Adding paragraphs (i) and (j).

The revisions and additions read as follows:

§ 63.7555 What records must I keep?

* * * * *

(d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

* * * * *

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under § 241.3(d)(1) of this chapter. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfy the definition of processing in § 241.2 of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per § 241.4 of this chapter, you must keep records documenting that the material is listed as a non-waste under § 241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(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.

(4) 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 12 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.

(5) 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 13 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.

(6) If, consistent with § 63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 13 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

* * * * *

(9) 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 14 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.

(10) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(11) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

* * * * *

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by § 63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

(i) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(j) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

■ 26. Section 63.7570 is amended by revising paragraph (a) and paragraph (b) introductory text to read as follows:

§ 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or an Administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(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 (5) 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.

* * * * *

■ 27. Section 63.7575 is amended by:

■ a. Adding in alphabetical order definitions for ''10-day rolling average,'' ''30-day rolling average,'' ''Annual capacity factor,'' ''Average annual heat input rate,'' ''Benchmark,'' ''Biodiesel,'' ''Daily block average,'' ''Efficiency credit,'' ''Energy management program,'' ''Fluidized bed boiler with an integrated fluidized bed heat exchanger,'' ''Heavy liquid,'' ''Light liquid,'' '' ''Major source for oil and natural gas production facilities,'' ''Minimum oxygen level,'' ''Other combustor'', ''Oxygen analyzer system'', ''Oxygen trim system'', ''Pile burner'', ''Regulated gas stream'', ''Residential boiler,'' ''Residual oil'', ''Secondary material,'' ''Shutdown'', ''Sloped grate'', ''Startup'', ''Stoker/sloped grate/other unit designed to burn kiln dried biomass,'' Stoker/sloped grate/other unit designed to burn wet biomass,'' ''Suspension burner,'' ''Total selected metals (TSM),'' ''Traditional fuel,'' ''Ultra low sulfur liquid fuel,'' ''Unit designed to burn heavy liquid subcategory,'' ''Unit designed to burn light liquid subcategory,'' and ''Vegetable oil.''

■ b. Revising the definitions for ''Boiler,'' ''Boiler system,'' ''Coal,'' Commercial/institutional boiler,'' ''Deviation,'' ''Distillate oil,'' ''Dry scrubber,'' ''Dutch oven,'' ''Electric utility steam generating unit,'' ''Energy assessment,'' ''Energy use system,'' ''Equivalent,'' ''Federally enforceable,'' ''Fluidized bed boiler'', ''Fuel cell,'' ''Fuel type,'' ''Gaseous fuel,'' ''Heat input,'' ''Hot water heater,'' ''Hybrid suspension grate boiler,'' ''Industrial boiler,'' ''Limited-use boiler or process heater,'' ''Liquid fuel,'' ''Load fraction,'' ''Metal process furnaces,'' ''Minimum activated carbon injection rate,'' ''Minimum scrubber liquid flow rate,'' ''Minimum sorbent injection rate,'' ''Natural gas,'' ''Other gas 1 fuel,'' ''Period of natural gas curtailment or supply interruption,'' ''Process heater,'' ''Qualified energy assessor,'' ''Residual oil,'' ''Solid fossil fuel,'' ''Steam output,'' ''Stoker,'' ''Temporary boiler,'' ''Tune-up,'' ''Unit designed to burn gas 1 subcategory,'' ''Unit designed to burn gas 2 (other) subcategory,'' ''Unit designed to burn liquid subcategory,'' ''Unit designed to burn liquid fuel that is a non-continental unit,'' ''Unit designed to burn solid fuel,'' ''Waste heat boiler,'' ''Waste heat process heater.''

■ c. Removing the definitions for ''Benchmarking,'' ''Emission credit,'' ''Liquid fuel subcategory,'' and ''Suspension boiler.''

The revisions read as follows:

§ 63.7575 What definitions apply to this subpart?

* * * * *

10-day rolling average means the arithmetic mean of the previous 240 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. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

30-day rolling average means 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. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent.

* * * * *

Annual capacity factor means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

Average annual heat input rate means total heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

* * * * *

Benchmark means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

Biodiesel means a mono-alkyl ester derived from biomass and conforming to ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see § 63.14).

* * * * *

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

* * * * *

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of ''coal'' includes synthetic fuels derived from coal, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

* * * * *

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

* * * * *

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown or downtime.

Deviation.

(1) *Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation.

* * * * *

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751–11b (incorporated by reference, see § 60.14).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be ''capable of combusting'' fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

* * * * *

Efficiency credit means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

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) 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) 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).

* * * * *

Energy management program means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

Energy use system includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot water systems; building envelop; and lighting; or other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

Equivalent means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite

consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an ''as received'' basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, HCl) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

* * * * *

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed boiler with an integrated fluidized bed heat exchanger means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

* * * * *

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are exempted from this definition.

Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

Heavy liquid includes residual oil and any other liquid fuel not classified as a light liquid.

* * * * *

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

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. 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.

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Light liquid includes distillate oil, biodiesel, or vegetable oil.

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 average 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, vegetable oil, and comparable fuels as defined under 40 CFR 261.38.

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).

Major source for oil and natural gas production facilities, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

Metal process furnaces are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

* * * * *

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

* * * * *

Minimum scrubber liquid flow rate means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

* * * * *

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, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

* * * * *

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

* * * * *

Other combustor means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

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

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

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

* * * * *

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

Pile burner means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

* * * * *

Qualified energy assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

* * * * *

Regulated gas stream means an offgas stream that is routed to a boiler or process heater for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

Residential boiler means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) used primarily to provide heat and/or hot water for:

(1) A dwelling containing four or fewer families; or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396–10 (incorporated by reference, *see* § 63.14(b)).

* * * * *

Secondary material means the material as defined in § 241.2 of this chapter.

Shutdown means the cessation of operation of a boiler or process heater for any purpose. Shutdown begins either when none of the steam from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler or process heater, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler or process heater.

Sloped grate means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire derived fuel.

* * * * *

Startup means either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat 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 steam or heat from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose.

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 calculated using Equations 21 through 25 of this section, as appropriate:

(i) For emission limits for boilers in the unit designed to burn solid fuel subcategory use Equation 21 of this section:

$$EL_{OBE} = EL_T \times 12.7\ MMBtu/Mwh \quad (Eq.\ 21)$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(ii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal use Equation 22 of this section:

$$EL_{OBE} = EL_T \times 12.2\ MMBtu/Mwh \quad (Eq.\ 22)$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass use Equation 23 of this section:

$$EL_{OBE} = EL_T \times 13.9\ MMBtu/Mwh \quad (Eq.\ 23)$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iv) For emission limits for boilers in one of the subcategories of units designed to burn liquid fuels use Equation 24 of this section:

$$EL_{OBE} = EL_T \times 13.8\ MMBtu/Mwh \quad (Eq.\ 24)$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(v) For emission limits for boilers in the unit designed to burn gas 2 (other) subcategory, use Equation 25 of this section:

$$EL_{OBE} = EL_T \times 10.4 \text{ MMBtu/Mwh} \quad \text{(Eq. 25)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

Stoker/sloped grate/other unit designed to burn kiln dried biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

Suspension burner means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

Temporary boiler means any gaseous or liquid fuel boiler 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 is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler 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 that replaces a temporary boiler 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, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Total selected metals (TSM) means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Traditional fuel means the fuel as defined in § 241.2 of this chapter.

Tune-up means adjustments made to a boiler or process heater in accordance with the procedures outlined in § 63.7540(a)(10).

* * * * *

Ultra low sulfur liquid fuel means a distillate oil that has less than or equal to 15 ppm sulfur.

* * * * *

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

Unit designed to burn heavy liquid subcategory means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

Unit designed to burn light liquid subcategory means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

Vegetable oil means oils extracted from vegetation.

* * * * *

Waste heat boiler means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

Waste heat process heater means an enclosed device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

* * * * *

■ 28. Table 1 to subpart DDDDD of part 63 is revised to 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 . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E–02 lb per MMBtu of heat input.	2.5E–02 lb per MMBtu of steam output or 0.28 lb per MWh.	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E–07 [a] lb per MMBtu of heat input.	8.7E–07 [a] lb per MMBtu of steam output or 1.1E–05 [a] lb per MWh.	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
2. Units designed to burn coal/solid fossil fuel.	a. Filterable PM (or TSM)	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	1.1E–03 lb per MMBtu of steam output or 1.4E–02 lb per MWh; or (2.7E–05 lb per MMBtu of steam output or 2.9E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 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 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, 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.
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, 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, 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, 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.
	b. Filterable PM (or TSM)	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	3.5E–02 lb per MMBtu of steam output or 4.2E–01 lb per MWh; or (2.7E–05 lb per MMBtu of steam output or 3.7E–04 lb per MWh).	Collect a minimum of 2 dscm per run.

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 . . .
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	4.2E–01 lb per MMBtu of steam output or 5.1 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E–02 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	3.5E–02 lb per MMBtu of steam output or 4.2E–01 lb per MWh; or (4.2E–03 lb per MMBtu of steam output or 5.6E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 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.
	b. Filterable PM (or TSM)	9.8E–03 lb per MMBtu of heat input; or (8.3E–05[a] lb per MMBtu of heat input).	1.2E–02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E–04[a] lb per MMBtu of steam output or 1.2E–03[a] lb per MWh).	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 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.
	b. Filterable PM (or TSM)	3.0E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	3.1E–02 lb per MMBtu of steam output or 4.2E–01 lb per MWh; or (6.6E–03 lb per MMBtu of steam output or 9.1E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 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.
	b. Filterable PM (or TSM)	3.2E–03 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	4.3E–03 lb per MMBtu of steam output or 4.5E–02 lb per MWh; or (5.2E–05 lb per MMBtu of steam output or 5.5E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E–02 lb per MMBtu of heat input; or (2.9E–05[a] lb per MMBtu of heat input).	3.0E–02 lb per MMBtu of steam output or 2.8E–01 lb per MWh; or (5.1E–05 lb per MMBtu of steam output or 4.1E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 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.
	b. Filterable PM (or TSM)	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input).	3.3E–02 lb per MMBtu of steam output or 3.7E–01 lb per MWh; or (5.5E–04 lb per MMBtu of steam output or 6.2E–03 lb per MWh).	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel.	a. HCl	4.4E–04 lb per MMBtu of heat input.	4.8E–04 lb per MMBtu of steam output or 6.1E–03 lb per MWh.	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E–07[a] lb per MMBtu of heat input.	5.3E–07[a] lb per MMBtu of steam output or 6.7E–06[a] lb per MWh.	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.

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 . . .
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.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 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).	1.5E–02 lb per MMBtu of steam output or 1.8E–01 lb per MWh; or (8.2E–05 lb per MMBtu of steam output or 1.1E–03 lb per MWh).	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E–03 [a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	1.2E–03 [a] lb per MMBtu of steam output or 1.6E–02 [a] lb per MWh; or (3.2E–05 lb per MMBtu of steam output or 4.0E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	2.5E–02 lb per MMBtu of steam output or 3.2E–01 lb per MWh; or (9.4E–04 lb per MMBtu of steam output or 1.2E–02 lb per MWh).	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.16 lb per MMBtu of steam output or 1.0 lb per MWh.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input.	2.9E–03 lb per MMBtu of steam output or 1.8E–02 lb per MWh.	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input.	1.4E–05 lb per MMBtu of steam output or 8.3E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	1.2E–02 lb per MMBtu of steam output or 7.0E–02 lb per MWh; or (3.5E–04 lb per MMBtu of steam output or 2.2E–03 lb per MWh).	Collect a minimum of 3 dscm per run.

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

[b] Incorporated by reference, see § 63.14.

[c] If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before January 31, 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.

■ 29. Table 2 to subpart DDDDD of part 63 is revised 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 . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E–02 lb per MMBtu of heat input.	2.5E–02 lb per MMBtu of steam output or 0.27 lb per MWh.	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.

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 . . .
	b. Mercury	5.7E–06 lb per MMBtu of heat input.	6.4E–06 lb per MMBtu of steam output or 7.3E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel.	a. Filterable PM (or TSM)	4.0E–02 lb per MMBtu of heat input; or (5.3E–05 lb per MMBtu of heat input).	4.2E–02 lb per MMBtu of steam output or 4.9E–01 lb per MWh; or (5.6E–05 lb per MMBtu of steam output or 6.5E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 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 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, 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, 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, 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.
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, 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.
	b. Filterable PM (or TSM)	3.7E–02 lb per MMBtu of heat input; or (2.4E–04 lb per MMBtu of heat input).	4.3E–02 lb per MMBtu of steam output or 5.2E–01 lb per MWh; or (2.8E–04 lb per MMBtu of steam output or 3.4E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	4.2E–01 lb per MMBtu of steam output or 5.1 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E–01 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	3.7E–01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E–03 lb per MMBtu of steam output or 5.6E–02 lb per MWh).	Collect a minimum of 1 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solid.	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 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.
	b. Filterable PM (or TSM)	1.1E–01 lb per MMBtu of heat input; or (1.2E–03 lb per MMBtu of heat input).	1.4E–01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E–03 lb per MMBtu of steam output or 1.7E–02 lb per MWh).	Collect a minimum of 1 dscm per run.

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 . . .
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, 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.
	b. Filterable PM (or TSM)	5.1E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	5.2E–02 lb per MMBtu of steam output or 7.1E–01 lb per MWh; or (6.6E–03 lb per MMBtu of steam output or 9.1E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid.	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 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.
	b. Filterable PM (or TSM)	2.8E–01 lb per MMBtu of heat input; or (2.0E–03 lb per MMBtu of heat input).	3.9E–01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E–03 lb per MMBtu of steam output or 2.8E–02 lb per MWh).	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid.	a. CO	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen.	2.4 lb per MMBtu of steam output or 12 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E–02 lb per MMBtu of heat input; or (5.8E–03 lb per MMBtu of heat input).	5.5E–02 lb per MMBtu of steam output or 2.8E–01 lb per MWh; or (1.6E–02 lb per MMBtu of steam output or 8.1E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate units designed to burn biomass/bio-based solid.	a. CO (or CEMS)	2,800 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, 30-day rolling average).	2.8 lb per MMBtu of steam output or 31 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.4E–01 lb per MMBtu of heat input; or (4.5E–04 lb per MMBtu of heat input).	5.5E–01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E–04 lb per MMBtu of steam output or 6.3E–03 lb per MWh).	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel.	a. HCl	1.1E–03 lb per MMBtu of heat input.	1.4E–03 lb per MMBtu of steam output or 1.6E–02 lb per MWh.	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E–06 lb per MMBtu of heat input.	2.5E–06 lb per MMBtu of steam output or 2.8E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 [b] collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	6.2E–02 lb per MMBtu of heat input; or (2.0E–04 lb per MMBtu of heat input).	7.5E–02 lb per MMBtu of steam output or 8.6E–01 lb per MWh; or (2.5E–04 lb per MMBtu of steam output or 2.8E–03 lb per MWh).	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E–03 lb per MMBtu of heat input; or (6.2E–05 lb per MMBtu of heat input).	9.6E–03 lb per MMBtu of steam output or 1.1E–01 lb per MWh; or (7.5E–05 lb per MMBtu of steam output or 8.6E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	0.13 lb per MMBtu of steam output or 1.4 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 . . .
	b. Filterable PM (or TSM)	2.7E–01 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	3.3E–01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E–03 lb per MMBtu of steam output or 1.2E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.16 lb per MMBtu of steam output or 1.0 lb per MWh.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input.	2.9E–03 lb per MMBtu of steam output or 1.8E–02 lb per MWh.	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input.	1.4E–05 lb per MMBtu of steam output or 8.3E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 2 dscm.
	d. Filterable PM (or TSM)	6.7E–03 lb per MMBtu of heat input or (2.1E–04 lb per MMBtu of heat input).	1.2E–02 lb per MMBtu of steam output or 7.0E–02 lb per MWh; or (3.5E–04 lb per MMBtu of steam output or 2.2E–03 lb per MWh).	Collect a minimum of 3 dscm per run.

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

[b] Incorporated by reference, see § 63.14.

■ 30. Table 3 to subpart DDDDD of part 63 is revised 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 . . .
1. A new or existing boiler or process heater with 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 in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater.	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.
2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid.	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.
3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater.	Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.
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 operates under an energy management program compatible with ISO 50001 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.

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

If your unit is . . .	You must meet the following . . .
	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 practices and provide recommendations for improvements consistent with the definition of energy management practices, 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.
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.	You must operate all CMS during startup. 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, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, and liquefied petroleum gas. If you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, 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, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose. You must comply with all applicable emission limits at all times except for startup or shutdown periods conforming with 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 coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases 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, SNCR, and SCR. 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.

■ 31. 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 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 most recent 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 control on a boiler 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 most recent 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 units not using a PM CPMS.	a. Maintain opacity to less than or equal to 10 percent opacity (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 units 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 (daily block average); or
	b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (i.e., COMS). 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 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 units 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 (daily block average).
7. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to § 63.7530(c)(1), (2) and/or (3) is less than the applicable emission limits.
8. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test.
9. 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 most recent 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).
10. 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 most recent HCl performance test, as specified in Table 8.

■ 32. Table 5 to subpart DDDDD of part 63 is amended by:

■ a. Revising the entry for ‘‘1. Particulate matter.’’

■ b. Remove the entry for ‘‘5. Dioxins/Furans’’.

■ c. Redesignating the entries for ‘‘2. Hydrogen chloride,’’ ‘‘3. Mercury,’’ and ‘‘4. CO’’ as ‘‘3. Hydrogen chloride,’’ ‘‘4. Mercury,’’ and ‘‘5. CO,’’ respectively.

■ d. Revising the newly redesignated entries for ‘‘4. Mercury’’ and ‘‘5. CO.’’

■ e. Add entry for ‘‘2. Total selected metals.’’

The revisions and addition 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 . . .
1. Filterable PM	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the PM emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A–3 or A–6 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
2. TSM	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.

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

To conduct a performance test for the following pollutant . . .	You must . . .	Using . . .
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–1 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the TSM emission concentration ...	Method 29 at 40 CFR part 60, appendix A–8 of this chapter
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
3. HCl	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–2 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the HCl emission concentration	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A–8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
4. Mercury	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–1 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the mercury emission concentration.	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A–8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784.[a]
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
5. CO	a. Select the sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine oxygen concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–3 of this chapter, or ASTM D6522–00 (Reapproved 2005), or ANSI/ASME PTC 19.10–1981.[a]
	c. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A–4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.

* * * * *

■ 33. 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 EPA 1631 or EPA 1631E or ASTM D6323[a] (for solid), or EPA 821–R–01–013 (for liquid or 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), EPA SW–846–3020A[a] (for liquid 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.

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

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
	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 ASTM D4177 [a] (for liquid fuels) or ASTM D4057 [a] (for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample.	ASTM D6722 [a] (for coal), EPA SW–846–7471B [a] (for solid samples), or EPA SW–846–7470A [a] (for liquid samples), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content.	Equation 8 in § 63.7530.
	h. Calculate the mercury emission rate from the boiler or process heater in units of pounds per million Btu.	Equations 10 and 12 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), EPA SW–846–3020A [a] (for liquid 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 ASTM D4177 [a] (for liquid fuels) or ASTM D4057 [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.	Equation 7 in § 63.7530.
	h. Calculate the HCl emission rate from the boiler or process heater in units of pounds per million Btu.	Equations 10 and 11 in § 63.7530.
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.	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 for solid fuels	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), EPA SW–846–3020A [a] (for liquid 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.	Equation 9 in § 63.7530.
	h. Calculate the TSM emission rate from the boiler or process heater in units of pounds per million Btu.	Equations 10 and 13 in § 63.7530.

[a] Incorporated by reference, see § 63.14.

■ 34. Table 7 to subpart DDDDD of part 63 is amended by:

■ a. Revising the entry for ''1. Particulate matter or mercury,''.

■ b. Revising the entry for ''2. Hydrogen Chloride,''.

■ c. Revising the entry for ''3. Mercury,''.

■ d. Revising the entry for ''4. Carbon monoxide''.

The revisions 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

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 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.
2. HCl	a. Wet scrubber operating parameters.	i. Establish site-specific minimum pressure drop, effluent pH, and flow rate operating limits according to § 63.7530(b).	(1) Data from the pressure drop, 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.
	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 (e.g., for 50 percent load, multiply the injection rate operating limit by 0.5) 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.

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS—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) The maximum SO_2 emission rate is equal to the lowest 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 (*e.g.,* actual heat input divided by heat input during performance test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
4. Carbon monoxide	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7520.	(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.

* * * * * * *

■ 35. Table 8 to subpart DDDDD of part 63 is revised to 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	a. Collecting the opacity monitoring system data according to § 63.7525(c) and § 63.7535; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. PM CPMS	a. Collecting the PM CPMS output data according to § 63.7525; b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to § 63.7530(b)(4).
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)(9) are met.
4. Wet Scrubber Pressure Drop and Liquid Flow-rate.	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(b).
5. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and

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 . . .
	b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to § 63.7530(b).
6. Dry Scrubber Sorbent or Carbon Injection Rate.	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in § 63.7575.
7. Electrostatic Precipitator Total Secondary Electric Power Input.	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to § 63.7530(b).
8. Emission limits using fuel analysis	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and b. Reduce the data to 12-month rolling averages; and c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 to this subpart.
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)(2). b. Reducing the data to 30-day rolling averages; and c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes. b. Maintaining the operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test according to § 63.7520(c).
11. SO_2 emissions using SO_2 CEMS	a. Collecting the SO_2 CEMS output data according to § 63.7525; b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average SO_2 CEMS emission rate to a level at or below the minimum hourly SO_2 rate measured during the most recent HCl performance test according to § 63.7530.

■ 36. Table 9 to subpart DDDDD of part 63 is amended by revising the entry for "1. Compliance report" 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	a. Information required in § 63.7550(c)(1) through (5); and	Semiannually, annually, biennially, or every 5 years according to the requirements in § 63.7550(b).
* * *	* *	* *

■ 37. Table 10 to subpart DDDDD of part 63 is amended by:
■ a. Revising the entry for "§ 63.6(i)".
■ b. Revising the entry for "§ 63.7(e)(1)".
■ c. Revising the entry for "63.8(g)".
■ d. Revising the entry for "§ 63.10(e) and (f)".
■ e. Adding an entry for "§ 63.10(e)".

The revisions and addition 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(i)	Extension of compliance	Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart.

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

Citation	Subject	Applies to subpart DDDDD
* * * * * * *		
§ 63.7(e)(1)	Conditions for conducting performance tests	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a) to (c).
* * * * * * *		
§ 63.8(g)	Reduction of monitoring data	Yes.
* * * * * * *		
§ 63.10(e)	Additional reporting requirements for sources with CMS.	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements.	Yes.
* * * * * * *		

■ 38. Add Table 11 to subpart DDDDD of part 63 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 designed to burn coal/solid fossil fuel.	a. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	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, 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, 10-day rolling average).	1 hr minimum sampling time.
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, 30-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 . . .
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, 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, 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.	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, 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, 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.
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, 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.	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, 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.

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 . . .
	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.	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
20. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	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 provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.
[b] Incorporated by reference, see § 63.14.

■ 39. Add Table 12 to subpart DDDDD of part 63 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.

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 . . .
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, 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, 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, 30-day rolling 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, 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, 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.	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, 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, 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, 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.

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 . . .
12. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 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, 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.	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.
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.	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.

■ 40. Add Table 13 to subpart DDDDD of part 63 to 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 JANUARY 31, 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 . . .
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	8.6E–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.
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, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.8E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
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, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.8E–02 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
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, 30-day rolling average).	1 hr minimum sampling time.
	b. 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. 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, 30-day rolling average).	1 hr minimum sampling time.
	b. 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.
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, 10-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.
7. 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.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.2E–01 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
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, 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 JANUARY 31, 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 . . .
	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.
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, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	5.1E–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.
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, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.6E–02 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
11. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 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.
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, 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.
13. Units designed to burn liquid fuel ..	a. HCl	1.2E–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.
	b. Mercury	4.9E–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.
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, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–03 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
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, 1-day block average)..	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E–03 [a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
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.

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 JANUARY 31, 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 . . .
	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 2 dscm per run.
17. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	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 and you are not required to conduct testing for CEMS or CPMS monitor certification, 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.

[FR Doc. 2012–31646 Filed 1–30–13; 8:45 am]

BILLING CODE 6560–50–P