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National Emission Standards for Hazardous Air Pollutants for Area
Sources: Industrial, Commercial, and Institutional Boilers; Final Rule

ENVIRONMENTAL PROTECTION AGENCY**40 CFR Part 63****[EPA-HQ-OAR-2006-0790; FRL-9698-5]****RIN 2060-AR14****National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers****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 reconsideration of certain issues related to the emission standards to control hazardous air pollutants from new and existing industrial, commercial and institutional boilers at area sources which were issued under section 112 of the Clean Air Act. As part of this action, the EPA is amending certain compliance dates for the standard and making technical corrections to the final rule to clarify definitions, references, applicability and compliance issues raised by petitioners and other stakeholders affected by the rule. The EPA today is taking final action on the proposed reconsideration.

DATES: This final rule is effective on February 1, 2013. The incorporation by reference of certain publications listed in this final rule were approved by the Director of the Federal Register as of February 1, 2013.

ADDRESSES: The EPA established a single docket under Docket ID No. EPA-HQ-OAR-2006-0790 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) 566-1741.

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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 emission standards for the source category of new and existing industrial, commercial, and institutional boilers located at area source facilities listed pursuant to CAA sections 112(c)(3), 112(c)(6), and 112(k)(3)(B).

Section 112(d) of the CAA requires the EPA to regulate HAP from both major and area stationary sources. Section 112(d)(5) of the CAA allows the EPA to establish standards for area sources of HAP "which provide for the use of generally available control technologies (GACT) or management practices by such sources to reduce emissions of hazardous air pollutants." While GACT serves as the basis for standards of most emissions from area source boilers, two pollutants emitted by coal-fired boilers, POM as 7-PAH and Hg, must be regulated based on the performance of MACT. These two pollutants are regulated based on MACT because area source industrial, commercial and institutional boilers combusting coal were listed under section 112(c)(6) of the CAA due to the source categories' emissions of POM and Hg. Section 112(c)(6) requires the EPA to regulate sources listed pursuant to that provision by issuing standards under section 112(d)(2) or (d)(4). The final rule meets this requirement by setting MACT standards for Hg and CO (as a surrogate for POM) for units in the coal-fired subcategory. Further, the final rule sets standards based on GACT for the urban HAP, other than Hg and POM, emitted from coal-fired boilers that pose the greatest public health risk, pursuant to section 112(c)(3) of the CAA, including arsenic, beryllium, cadmium, lead, chromium, manganese, nickel, ethylene dioxide, and PCBs. In addition, the final rule sets standards based on GACT for boilers combusting oil or biomass for urban HAP, including Hg, arsenic, beryllium, cadmium, lead, chromium, manganese, nickel, POM, ethylene dioxide, and PCBs.

In developing the MACT standards for coal-fired boilers, the EPA considered section 112(h) of the CAA, which allows the EPA to establish work practice standards in lieu of numerical emission limits under section 112(d)(2) only in cases where the agency determines that it is not feasible to prescribe or enforce an emission standard. The EPA has set work practice standards for emissions of Hg and POM from small coal-fired boilers, pursuant to section 112(h), in the form of periodic tune-ups.

This final rule amends certain provisions of the final rule issued by EPA on March 11, 2011, and responds to petitions for reconsideration filed by a number of different entities.

Summary of Major Reconsideration Provisions

In general, the final rule requires facilities classified as area sources of HAP with affected boilers to reduce emissions of harmful toxic air emissions from these combustion sources, improving air quality, and protecting public health in communities where these facilities are located.

Recognizing the diversity of this source category and the multiple sectors of the economy this rule affects, the EPA is establishing seven subcategories for boilers based on the design of the combustion equipment and operating schedules of the unit. In addition to the coal, biomass, and oil subcategories in the March 2011 final rule, we are establishing subcategories for seasonal boilers, limited-use boilers, oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr, and certain boilers that use a continuous oxygen trim system.

Numerical emission limits, based on MACT, are established for Hg and CO at new and existing large coal-fired boilers (i.e., with a design heat input capacity of 10 MMBtu/hr or more). A review of the data has resulted in changes to the Hg and CO emission limits contained in the March 2011 final rule. The EPA is also establishing a CEMS alternative compliance option for the numeric CO emission limit. Coal-fired boilers subject to a CO emission limit can comply with the limit using a periodic stack test and CPMS, or by using CEMS. The CO CEMS alternative compliance option is based on a 10-day rolling average and provides additional compliance flexibility to sources with existing CO CEMS equipment. New and existing small coal-fired units (i.e., with a design heat input capacity of less than 10 MMBtu/hr) are subject to periodic tune-up work practices for CO and Hg in lieu of numeric emission limits because the EPA found that it was technologically

and economically impracticable to apply measurement methodology to these small sources, pursuant to CAA section 112(h).

Numerical emission limits, based on GACT, are established for PM as a surrogate for urban metal HAP other than Hg for new large coal-fired boilers. New and existing small coal-fired boilers are subject to periodic tune-up management practices for PM as a surrogate for urban metal HAP other than Hg, and for CO as a surrogate for urban organic HAP other than POM, based on GACT.

New large biomass- and oil-fired boilers are subject to numerical emission limits for PM as a surrogate for urban metal HAP, based on GACT. Existing biomass and oil-fired boilers and new small biomass- and oil-fired boilers are subject to periodic tune-up management practices for PM as a surrogate for urban metal HAP, based on GACT. New and existing biomass- and oil-fired boilers are subject to periodic tune-up management practices for CO as a surrogate for urban organic HAP, based on GACT. Certain other subcategories (seasonal boilers, limited-use boilers, oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr, and boilers with an oxygen trim system) are subject to periodic tune-up work practice or management practice requirements tailored to their schedule of operation and types of fuel.

The compliance date for existing sources is March 21, 2014. The compliance date for new sources that began operations on or before May 20, 2011 is May 20, 2011. For new sources that start up after May 20, 2011, the compliance date is the date of startup. New sources are defined as sources that began operation after June 4, 2010.

Costs and Benefits

This final action is intended to clarify definitions, references, applicability and compliance issues, but not change the coverage of the final rule. The final rule will affect an estimated 180,000 existing area source boilers and the EPA projects that approximately an additional 6,800 new boilers will be subject to the rule over the initial 3-year period. The clarifications should make it easier for owners and operators and for local and state authorities to understand and implement the rule's requirements. As compared to the March 2011 final rule, this final rule will not affect the estimated emission reductions, control costs or the benefits of the rule in substance. This final rule does not impose any additional regulatory requirements beyond those imposed by

the previously promulgated boiler area source rule and, in fact, will result in a decrease in regulatory requirements for certain subcategories of boilers. A more detailed discussion of the costs and benefits of the March 2011 final rule is provided at 76 FR 15579, March 21, 2011, and 76 FR 80542, December 23, 2011. Section VI of this preamble provides a discussion of the impacts of this final rule.

SUPPLEMENTARY INFORMATION:

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

7-PAH 7-polynuclear aromatic hydrocarbons
ACI activated carbon injection
ASTM American Society for Testing and Materials
Btu British thermal unit
CO carbon monoxide
CEMS continuous emission monitoring system
CDX Central Data Exchange
CAA Clean Air Act
CFR Code of Federal Regulations
COMS continuous opacity monitoring system
CPMS continuous parameter monitoring system
DOE Department of Energy
ERT Electronic Reporting Tool
ESP electrostatic precipitator
FR Federal Register
GACT generally available control technologies
HAP hazardous air pollutants
Hg mercury
HQ Headquarters
ISO International Standards Organization
lb pounds
MACT maximum achievable control technology
MMBtu million British thermal units
NAA No Action Assurance
NAICS North American Industry Classification System
NESHAP national emission standards for hazardous air pollutants
NSPS new source performance standard
NTTAA National Technology Transfer and Advancement Act
OMB Office of Management and Budget
PCBs polychlorinated biphenyls
PM particulate matter
POM polycyclic organic matter
ppm parts per million
PSD prevention of significant deterioration
RFA Regulatory Flexibility Act
RIN Regulatory Information Number
TBtu trillion British thermal units
TTN Technology Transfer Network
tpy tons per year
UMRA Unfunded Mandates Reform Act of 1995
UPL upper prediction limit
VCS Voluntary Consensus Standards
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?
- B. Where can I get a copy of this document?
- C. Judicial Review
- II. Background Information
- III. Summary of Final Action on Reconsideration
 - A. Affected Sources
 - B. Source Category Exclusions
 - C. Emission Limits
 - D. Tune-Up Work Practice and Management Practice Standards
 - E. Energy Assessment Work Practice and Management Practice Standards
 - F. GACT-Based Standards
 - G. Initial Compliance
 - H. Operating Limits
 - I. Continuous Compliance
 - J. Periods of Startup and Shutdown
 - K. Affirmative Defense Language
 - L. Notification, Recordkeeping and Reporting Requirements
 - M. Title V Permitting Requirements
 - N. Definition of Period of Gas Curtailment or Supply Interruption
 - O. Miscellaneous Technical Corrections
 - P. Other Issues
- IV. Summary of Significant Changes Since Proposed Action on Reconsideration
 - A. Applicability
 - B. Tune-Up Requirements
 - C. Energy Assessment
 - D. Clarification of Oxygen Concentration Operating Limits
 - E. Definitions Regarding Averaging Times
 - F. Fuel Sampling Frequency
 - G. Performance Testing Frequency
 - H. Startup and Shutdown Definitions
 - I. Notifications
 - J. Miscellaneous Definitions
- V. Other Actions the EPA Is Taking
- VI. Impacts Associated With This 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
 - B. Paperwork Reduction Act
 - C. Regulatory Flexibility Act
 - D. Unfunded Mandates Reform Act
 - E. Executive Order 13132: Federalism
 - F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
 - G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
 - H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
 - I. National Technology Transfer and Advancement Act
 - J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
 - K. Congressional Review Act

I. General Information

A. Does this action apply to me?

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

Industry category	NAICS Code ^a	Examples of regulated entities
Any area source facility using a boiler as defined in the final rule.	321	Wood product manufacturing.
.....	11	Agriculture, greenhouses.
.....	311	Food manufacturing.
.....	327	Nonmetallic mineral product manufacturing.
.....	424	Wholesale trade, nondurable goods.
.....	531	Real estate.
.....	611	Educational services.
.....	813	Religious, civic, professional, and similar organizations.
.....	92	Public administration.
.....	722	Food services and drinking places.
.....	62	Health care and social assistance.
.....	22111	Electric power generation.

^aNorth 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 final action. To determine whether your facility may be affected by this action, you should examine the applicability criteria in 40 CFR 63.11193 of subpart JJJJJ (National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources). If you have any questions regarding the applicability of this final rule to a particular entity, consult either the air permit 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 2, 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.

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 EPA to enforce these requirements.

II. Background Information

Section 112(d) of the CAA requires the EPA to establish NESHAP for both major and area sources of HAP that are listed for regulation under CAA section 112(c). A major source is any stationary source that emits or has the potential to emit 10 tpy or more of any single HAP or 25 tpy or more of any combination of HAP. An area source is a stationary source that is not a major source.

On March 21, 2011 (76 FR 15554), the EPA issued the NESHAP for industrial, commercial and institutional area source boilers pursuant to CAA sections 112(c)(3), 112(c)(6), and 112(k)(3)(B).

CAA section 112(k)(3)(B) directs the EPA to identify at least 30 HAP that, as a result of emissions from area sources, pose the greatest threat to public health in the largest number of urban areas. The EPA implemented this provision in 1999 in the Integrated Urban Air Toxics Strategy, (64 FR 38715, July 19, 1999) (Strategy). Specifically, in the Strategy, the EPA identified 30 HAP that pose the greatest potential health threat in urban areas, and these HAP are referred to as the "30 urban HAP." Section 112(c)(3) of the CAA requires the EPA to list sufficient categories or subcategories of area sources to ensure that area sources representing 90 percent of the emissions of the 30 urban HAP are subject to regulation. Under CAA section 112(d)(5), the EPA may elect to promulgate standards or requirements for area sources "which provide for the use of generally available control technologies ("GACT") or management practices by such sources to reduce emissions of hazardous air pollutants."

CAA section 112(c)(6) requires that the EPA list categories and subcategories of sources assuring that sources accounting for not less than 90 percent of the aggregate emissions of each of seven specified HAP are subject

to standards under CAA sections 112(d)(2) or (d)(4), which require the application of the more stringent MACT. The seven HAP specified in CAA section 112(c)(6) are as follows: Alkylated lead compounds, POM, hexachlorobenzene, Hg, PCBs, 2,3,7,8-tetrachlorodibenzofuran, and 2,3,7,8-tetrachlorodibenzo-p-dioxin.

As noted in the preamble to the final rule, (76 FR 15556, March 21, 2011), we listed area source industrial boilers and commercial/institutional boilers combusting coal under CAA section 112(c)(6) based on the source categories' contribution of Hg and POM, and under CAA section 112(c)(3) for their contribution of arsenic, beryllium, cadmium, lead, chromium, manganese, nickel, ethylene dioxide, and PCBs, as well as Hg and POM. We promulgated final standards for coal-fired area source boilers to reflect the application of MACT for Hg and POM, and to reflect GACT for the urban HAP other than Hg and POM.

We listed industrial and commercial/institutional boilers combusting oil or biomass under CAA section 112(c)(3) for their contribution of Hg, arsenic, beryllium, cadmium, lead, chromium, manganese, nickel, POM, ethylene dioxide, and PCBs. For boilers firing oil or biomass, the final standards reflect GACT for all of the urban HAP.

On March 21, 2011, we also published a notice to initiate the reconsideration of certain aspects of the final rule for area source industrial, commercial and institutional boilers (76 FR 15266). The reconsideration notice identified several provisions of the final rule where additional public comment was appropriate. The notice also identified several issues of central relevance to the rulemaking where reconsideration was appropriate under CAA section 307(d).

Following promulgation of the final rule, the EPA also received petitions for reconsideration from the following organizations (Petitioners): American

Sugar Cane League of the U.S.A., Alaska Oil and Gas Association, American Coke and Coal Chemicals Institute, American Iron and Steel Institute, American Petroleum Institute, Council of Industrial Boiler Owners, Industry Coalition (American Forest and Paper Association (AF&PA) et. al.), National Petrochemical and Refiners Association, Sierra Club, and the State of Washington Department of Ecology. Petitioners, pursuant to CAA section 307(d)(7)(B), requested that the EPA reconsider numerous provisions in the rules. 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:

- Establishing separate requirements for seasonally operated boilers.
- Addressing temporary boilers.
- Clarifying the initial compliance schedule for existing boilers subject to tune-ups.
- Defining periods of gas curtailment.
- Providing an optional CO compliance mechanism using CEMS.
- Averaging times for parameter monitoring.
- Providing an affirmative defense for malfunction events.
- Adjusting frequency of tune-up work practices for very small units.
- Selecting a 99 percent confidence interval for setting the CO emission limit.
- Establishing GACT-based limits for biomass and oil-fired boilers.
- Scope and duration of the energy assessment and deadline for completing the assessment.
- Revising GACT-based limits for PM at new oil-fired boilers.
- Exempting area sources from title V permitting requirements.

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

III. Summary of Final Action on Reconsideration

As stated above, the December 23, 2011, proposed rule addressed specific issues and provisions the EPA identified for reconsideration. This summary reflects the agency's final action 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.

A. Affected Sources

This final rule amends 40 CFR 63.11194 to specify that an existing dual-fuel fired boiler (*i.e.*, commenced construction or reconstruction on or before June 4, 2010) meeting the definition of gas-fired boiler, as defined in 40 CFR 63.11237, that meets the applicability requirements of subpart JJJJJJ after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be an existing source under this subpart as long as the boiler was designed to accommodate the alternate fuel. A new or reconstructed dual-fuel fired boiler (*i.e.*, commenced construction or reconstruction after June 4, 2010) meeting the definition of gas-fired boiler, as defined in 40 CFR 63.11237, that meets the applicability criteria of subpart JJJJJJ after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be a new source under this subpart.

B. Source Category Exclusions

This final rule amends the list of boilers that are not part of the source categories subject to subpart JJJJJJ. We are revising this list (as set forth in 40 CFR 63.11195) to clarify certain boiler types and to include certain additional boilers that may be located at an industrial, commercial or institutional area source facility. These revisions of the source categories are described below.

1. Electric Boilers

The EPA is amending 40 CFR 63.11195 by adding electric boilers to the list of boilers not subject to subpart JJJJJJ. Electric boilers are defined in 40 CFR 63.11237 as follows:

Electric boiler means a boiler in which electric heating serves as the source of heat. Electric boilers that burn gaseous or liquid fuel during periods of electrical power curtailment or failure are included in this definition.

2. Residential Boilers

The EPA is amending 40 CFR 63.11195 by adding residential boilers to the list of boilers not subject to subpart JJJJJJ. We are clarifying that a residential boiler may be part of a residential combined heat and power system and that a boiler serving a single unit residence dwelling that has since been converted or subdivided into condominiums or apartments may also be considered a residential boiler. Residential boilers are defined in 40 CFR 63.11237 as follows:

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.

3. Temporary Boilers

The EPA is amending 40 CFR 63.11195 by adding temporary boilers to the list of boilers not subject to subpart JJJJJJ. Similar to residential boilers, we did not intend to regulate temporary boilers under the area source standards because they are not part of either the industrial boiler source category or the commercial/institutional boiler source category. We note that neither the CAA section 112(c)(6) inventory nor the CAA section 112(c)(3) inventory included temporary boilers. In this final action, the EPA is simply clarifying the scope of categories regulated by subpart JJJJJJ. By their nature of being temporary, these boilers are operating in place of another non-temporary boiler while that boiler is being constructed, replaced or repaired, in which case we would have counted the non-temporary boiler as one being regulated. Additionally, the final major source rule for boilers excludes temporary boilers.

The definition of "temporary boiler" specifies that a boiler is not a temporary boiler if it 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. The definition of "temporary boiler" also specifies that any temporary boiler that replaces a temporary boiler at a location within the facility and performs the same or similar function will be included in calculating the consecutive time period unless there is a gap in operation of 12 months or more. Temporary boilers are defined in 40 CFR 63.11237 as follows:

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 regulatory 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 within the facility and performs the same or similar function will be included in calculating the consecutive time period unless there is a gap in operation of 12 months or more.

(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.

4. Boilers With Section 3005 Permits

The EPA is clarifying the language in 40 CFR 63.11195(c) to provide an exclusion stating “unless such units do not combust hazardous waste and combust comparable fuels” such that it reads: “A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (e.g., hazardous waste boilers), unless such units do not combust hazardous waste and combust comparable fuels.”

5. Boilers Used as Control Devices

The EPA is amending the language in 40 CFR 63.11195(g) to clarify that any boiler that is used as a control device to comply with a subpart under part 60, 61, or 65 of chapter 40 is not subject to subpart JJJJJ provided that at least 50 percent of the heat input to the boiler is provided by the gas stream that is regulated under another subpart.

C. Emission Limits

1. Hg Emission Limit for Coal-Fired Boilers

The EPA is amending the Hg emission limit for large coal-fired boilers to 0.000022 lb per MMBtu based on a revised analysis. The revised analysis excludes data for a utility boiler that were erroneously used as the basis for the Hg emission limit included in the March 2011 final rule. Further discussion of this revision to the Hg emission limit is located in the December 23, 2011, proposal (76 FR 80541).

A memorandum “*Beyond-the-Floor Analysis for Mercury and Carbon Monoxide*” located in the docket for the rulemaking describes our beyond-the-floor analysis for Hg and CO emissions from new and existing area source coal-fired boilers with heat input capacity of 10 MMBtu/hr or greater. In the beyond-the-floor option for Hg emissions, new

and existing coal-fired boilers would be required to comply with a Hg emission limit more stringent than the MACT floor-based emission limit of 2.2×10^{-5} lb of Hg per MMBtu. To comply with a limit more stringent than the fabric filter-based MACT floor limit, it is expected that an affected boiler would need to employ fabric filter control along with ACI. In summary, we determined that the beyond-the-floor option of installing ACI for Hg control from area source coal-fired boilers is not economically feasible.

As discussed in the preamble to the June 2010 proposed rule (75 FR 31896) and the preamble to the March 2011 final rule (76 FR 15554), we also considered whether fuel switching was an appropriate control technology for purposes of determining either the MACT floor level or beyond-the-floor level of control. We determined that fuel switching was not an appropriate floor or beyond-the-floor control. As also discussed in the June 2010 and March 2011 preambles, we determined that an energy assessment requirement was an appropriate beyond-the-floor option for existing large boilers. These previous analyses continue to be applicable for mercury.

2. Using the UPL for Setting the CO Emission Limit

The EPA is amending the CO emission limit for coal-fired boilers to reflect a revised analysis that uses the 99 percent confidence level in determining the UPL. Based on the results of the revised analysis, we are amending the CO emission limit for new and existing coal-fired boilers from 400 ppm by volume on a dry basis, corrected to 3 percent oxygen, to 420 ppm by volume on a dry basis, corrected to 3 percent oxygen.

As discussed in the “*Beyond-the-Floor Analysis for Mercury and Carbon Monoxide*” memorandum, to comply with a limit more stringent than the MACT floor based CO limit, it is expected that new and existing area source coal-fired boilers with heat input capacity of 10 MMBtu/hr or greater may need to install an oxidation catalyst. As fully explained in the memorandum, we determined that the beyond-the-floor option of installing an oxidation catalyst for CO control was technically infeasible. Other methods of reducing CO emissions, such as upgrading new burners and overfire air systems, were also considered and determined to be technically infeasible options. As explained earlier in this preamble, we determined that fuel switching was not an appropriate floor or beyond-the-floor control and that an energy assessment

requirement was an appropriate beyond-the-floor option for existing large boilers. These previous analyses continue to be applicable for CO.

3. Compliance Alternative for PM for Certain Oil-Fired Boilers

The EPA is amending the applicability of PM emission limit requirements for certain new or reconstructed oil-fired boilers. We are amending 40 CFR 63.11210 to specify that new or reconstructed oil-fired boilers satisfy GACT for PM when they combust only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM emission limit under this subpart and do not use a post-combustion technology (except a wet scrubber) to reduce PM or sulfur dioxide emissions.

D. Tune-Up Work Practice and Management Practice Standards

1. Requirements for Seasonally Operated Boilers

The EPA is establishing separate requirements for a subcategory of boilers that are seasonally operated. For seasonally operated boilers, we are amending 40 CFR 63.11223 to specify that these boilers are required to complete a tune-up every 5 years, instead of on a biennial basis as is required for most non-seasonal boilers. Specifically, existing seasonal boilers are required to complete the initial tune-up by March 21, 2014, and a subsequent tune-up every 5 years after the initial tune-up. New and reconstructed seasonal boilers are not required to complete an initial tune-up, but are required to complete a tune-up every 5 years after the initial startup of the new or reconstructed boiler.¹ A combined total of 15 days of periodic testing of the seasonal boiler during the 7-month shutdown is allowed. The definition of “seasonal boiler” clarifies that it only applies to biomass- or oil-fired boilers. Seasonally operated boilers are defined in 40 CFR 63.11237 as follows:

Seasonal boiler means a boiler that undergoes a shutdown for a period of at least 7 consecutive months (or 210 consecutive days) each 12-month period due to seasonal conditions, except for periodic testing. Periodic testing shall not exceed a combined total of 15 days during the 7-month shutdown. This definition only applies to

¹ Generally, boilers are initially installed optimized for efficiency, i.e., “in tune.” Periodic tune-ups restore a boiler to its efficient state, given its age and other parameters. We do not require a tune-up upon startup because boilers normally would already be efficient at that time. Emission reductions are projected to occur by maintaining efficient combustion through periodic tune-ups.

boilers that would otherwise be included in the biomass subcategory or the oil subcategory.

2. Requirements for Small Oil-Fired Units

The EPA is establishing separate requirements for a subcategory of oil-fired boilers with a heat input capacity of equal to or less than 5 MMBtu/hr. We are amending 40 CFR 63.11223 to specify that this subcategory of small oil-fired boilers are required to complete a tune-up every 5 years, instead of on a biennial basis as is required for most larger oil-fired boilers. Specifically, existing oil-fired boilers with a heat input capacity of equal to or less than 5 MMBtu/hr are required to complete the initial tune-up by March 21, 2014, and a subsequent tune-up every 5 years after the initial tune-up. New and reconstructed oil-fired boilers with a heat input capacity of equal to or less than 5 MMBtu/hr are not required to complete an initial tune-up, but are required to complete a tune-up every 5 years after the initial startup of the new or reconstructed boiler.

3. Requirements for Boilers With Oxygen Trim Systems

The EPA is establishing separate requirements for boilers with oxygen trim systems that maintain an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up. We are amending 40 CFR 63.11223 to specify that this subcategory of boilers is required to complete a tune-up every 5 years. Specifically, existing boilers with oxygen trim systems are required to complete the initial tune-up by March 21, 2014, and a subsequent tune-up every 5 years after the initial tune-up. New and reconstructed boilers with oxygen trim systems are not required to complete an initial tune-up, but are required to complete a tune-up every 5 years after the initial startup of the new or reconstructed boiler.

4. Requirements for Limited-Use Boilers

The EPA is establishing separate requirements for a subcategory of boilers that operate on a limited basis. The limited-use subcategory includes any boiler that burns any amount of solid or liquid fuels and has a federally enforceable average annual capacity factor of no more than 10 percent. For limited-use boilers, we are amending 40 CFR 63.11223 of the final rule to specify that these boilers are required to complete a tune-up every 5 years. Specifically, existing limited-use boilers are required to complete the initial tune-up by March 21, 2014, and a subsequent tune-up every 5 years after the initial

tune-up. New and reconstructed limited-use boilers are not required to complete an initial tune-up, but are required to complete a tune-up every 5 years after the initial startup of the new or reconstructed boiler. Limited-use boilers are not subject to the emission limits in Table 1 to the subpart, the energy assessment requirements in Table 2 to the subpart, or the operating limits in Table 4 to the subpart.

E. Energy Assessment Work Practice and Management Practice Standards

1. Scope

The EPA is amending the definition of “energy assessment” to clarify that the scope of the energy assessment does not encompass energy use systems located off-site or energy use systems using electricity purchased from an off-site source. The energy assessment is limited to only those energy use systems, located on-site, associated with the affected boilers. We are also clarifying that the scope of the assessment is based on energy use by discrete segments of a facility (e.g., production area or building) and not by a total aggregation of all individual energy using segments of a facility.

The definition of “boiler system” is being revised in this final rule to clarify that it means the boiler and associated components directly connected to and serving the energy use systems. We are amending the definition of “energy use system” to clarify that energy use systems are only those systems using energy clearly produced by affected boilers.

We are clarifying that energy assessor approval and qualification requirements are waived in instances where an energy assessment completed on or after January 1, 2008 meets or is amended to meet the energy assessment requirements in this final rule by March 21, 2014. Finally, we are specifying that a source that is operating under an energy management program established through energy management systems compatible with ISO 50001, that includes the affected boilers, by March 21, 2014, satisfies 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.

2. Compliance Date

As specified in 40 CFR 63.11196(a)(3), existing boilers that are subject to the energy assessment requirement must achieve compliance with the energy assessment requirement no later than March 21, 2014. Thus, in order to meet the requirements of the rule, energy assessments must, therefore, be completed by the compliance date (March 21, 2014) for existing sources.

3. Maximum Duration Requirements

The EPA is amending the definition of “energy assessment” for facilities with affected boilers with less than 0.3 TBtu/yr heat input capacity and for facilities with affected boilers with 0.3 to 1 TBtu/yr heat input capacity to change the maximum time to conduct the energy assessment from one day to 8 on-site technical hours and from three days to 24 on-site technical hours, respectively, and to allow sources to perform longer assessments at their discretion. We are also amending the definition of “energy assessment” for facilities with affected boilers with greater than 1 TBtu/yr heat input capacity to specify that the maximum time to conduct the assessment is up to 24 on-site technical hours for the first TBtu/yr plus 8 on-site technical 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.

F. GACT-Based Standards

1. Establishing GACT-Based Emission Limits for Biomass- and Oil-Fired Boilers

The EPA is not amending the GACT-based standards, as specified in the March 21, 2011, final rule, for biomass- and oil-fired boilers. Specifically, the final standards for biomass- and oil-fired area source boilers are based on GACT instead of MACT as were the proposed standards for all pollutants except POM. Our rationale for the changes between proposal and promulgation for the biomass- and oil-fired boilers, including not requiring MACT for POM, can be found in the preamble to the promulgated area source standards (76 FR 15565–15567 and 15574–15575, March 21, 2011). The final standards for area source biomass- and oil-fired boilers require these boilers to meet the following standards:

New boilers with heat input capacity greater than 10 MMBtu/hr that are biomass-fired or oil-fired must meet GACT-based numerical emission limits for PM.

New boilers with heat input capacity greater than 10 MMBtu/hr that are biomass-fired or oil-fired must comply

with work practice standards to minimize the boiler's startup and shutdown periods following the manufacturer's recommendations, or the manufacturer's recommendations for a unit of similar design.

Existing boilers with heat input capacity greater than 10 MMBtu/hr that are biomass-fired or oil-fired 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 final rule by March 21, 2014, or an energy management program established through energy management systems compatible with ISO 50001, that includes the affected boilers, by March 21, 2014, under which the owner or operator currently operates.

All new and existing units, regardless of size, that are biomass-fired or oil-fired must have a GACT-based periodic tune-up.

2. Setting GACT-Based PM Standards for New Oil-Fired Boilers

The EPA is not making any changes to the PM limit for new oil-fired boilers. New oil-fired boilers with heat input capacity greater than 10 MMBtu/hr must meet a GACT-based numerical emission limit for PM (0.03 lb per MMBtu of heat input). New oil-fired units, regardless of size, must have a GACT-based periodic tune-up. Our rationale for finalizing GACT-based PM emissions limits can be found in the preamble to the promulgated area source standards (76 FR 15574, March 21, 2011).

G. Initial Compliance

1. Dates

Some commenters have argued that the 3-year compliance deadline of March 21, 2014, for existing sources to meet the standards does not provide sufficient time for sources to meet the standards in view of the large number of sources subject to the rule and that these sources 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 standards should be able to meet the standards within 3 years (*i.e.*, by March 21, 2014), even those that need to install pollution control technologies to do so. In addition, many sources subject to the standards are existing biomass- or oil-fired boilers or small coal-fired boilers (less than 10 MMBtu/hr) and will not

need to install controls in order to demonstrate compliance, as these sources are subject only to work practices or management practices.

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 1 year if such time is needed for the installation of controls. *See* CAA section 112(i)(3)(B)). Permitting authorities are already familiar with, and in many cases have experience with, applying the 1-year extension authority under section 112(i)(3)(B) since the provision applies to all NESHAP. *See* 40 CFR 63.6(i)(4)(A). We believe that should the range of circumstances that commenters have cited as impeding sources' ability to install controls within 3 years materialize, then permitting authorities can take those circumstances into consideration when evaluating an existing source's request for a 1-year extension, and where such applications prove to be well-founded, permitting authorities can make the 1-year extension available to applicants.

In making a determination as to whether an extension is appropriate, we believe it is 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 the Major Source Boilers Standards and the Mercury and Air Toxics Standards 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 may be 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 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.

2. Demonstrating Initial Compliance

The EPA is amending 40 CFR 63.11210 to clarify the dates by which new and reconstructed boilers need to demonstrate initial compliance. We are amending 40 CFR 63.11210(d) to clarify that only boilers that are subject to emission limits for PM, Hg or CO in Table 1 to subpart JJJJJ have a 180-day period after the applicable compliance date to demonstrate initial compliance.

We are adding a new paragraph (i) to 40 CFR 63.11210 to clarify the initial compliance requirements for boilers located at existing major sources of HAP that become area sources on a timely basis. Any such existing boiler at the existing source must demonstrate compliance with subpart JJJJJ within 180 days of the later of March 21, 2014 or upon the existing major source commencing operation as an area source. Any new or reconstructed boiler at the existing source must demonstrate compliance with subpart JJJJJ within 180 days of the later of March 21, 2011 or startup. Notification of such changes must be submitted according to 40 CFR 63.11225(g).

We are adding a new paragraph (j) to 40 CFR 63.11210 that specifies initial compliance demonstration requirements for existing affected boilers that have not operated between the effective date of the rule and the source's compliance date. Owners and operators of boilers subject to emission limits must complete the initial compliance demonstration no later than 180 days after the re-start of the affected boiler, sources subject to tune-up requirements must complete the initial performance tune-up no later than 30 days after the re-start of the affected boiler, and sources subject to the one-time energy assessment must complete the assessment no later than the compliance date specified in 40 CFR 63.11196.

3. Schedule for Existing Boilers Subject to Tune-Up Requirements

The EPA is amending 40 CFR 63.11196 to specify that all existing boilers subject to the tune-up requirement have 3 years (by March 21, 2014) in which to demonstrate initial compliance, instead of 1 year as specified in the 2011 final rule (76 FR 15554, March 21, 2011) or 2 years as specified in the proposed reconsideration of final rule action (76

FR 80532, December 23, 2011). In the December 23, 2011, proposal, we specifically requested comment on whether the initial compliance period for the tune-up requirement should be extended to March 21, 2014.

4. Conducting Initial Tune-Ups at New and Reconstructed Sources

The EPA is removing the requirement for an initial tune-up for new and reconstructed boilers. Thus, new and reconstructed units are required to complete the applicable biennial or 5-year tune-up no later than 25 months or 61 months, respectively, after the initial startup of the new or reconstructed boiler.

5. Fuel Requirements

The EPA is amending 40 CFR 63.11223(a) to specify that boiler tune-ups must be conducted while burning the type of fuel that provided the majority of the heat input to the boiler over the 12 months prior to the tune-up.

H. Operating Limits

1. Operating Limits for Oxygen Concentration

The EPA is clarifying that the oxygen concentration must be at or above the minimum established during a performance stack test. These limits have also been clarified to be applicable when the unit is firing the fuel or fuel mixture utilized during the CO performance test.

2. Maximum Operating Load

The EPA is including provisions for establishing a unit-specific limit for maximum operating load that applies to any boiler subject to an emission limit for which compliance is demonstrated by a performance stack test. Operating load data includes fuel feed rate data or steam generation rate data.

3. Establishing Operating Limits for Wet Scrubbers

The EPA is amending the operating limit provisions in 40 CFR 63.11211(b)(2) for an ESP operated with a wet scrubber to remove the statement that the operating limits for ESP do not apply to dry ESP systems operated without a wet scrubber.

I. Continuous Compliance

1. CO Emission Limit

The March 2011 final rule requires sources subject to a CO emission limit to demonstrate compliance by measuring CO emissions while also monitoring the oxygen content of the exhaust. We are amending the monitoring requirements in 40 CFR

63.11224(a) to allow sources subject to a CO emission limit the option to install, operate, and maintain CO and oxygen CEMS. The CEMS must be installed, operated and maintained according to Performance Specifications 3 and 4, 4A, or 4B at 40 CFR part 60, appendix B, and according to the site-specific monitoring plan that each facility is required to develop. The CEMS will also be required to complete a performance evaluation, also according to Performance Specifications 3 and 4, 4A, or 4B.

Sources have the option to demonstrate continuous compliance by monitoring both CO and oxygen using CEMS to demonstrate compliance with the CO emission limit, corrected to 3 percent oxygen, or monitoring and complying with an oxygen content operating limit that is established during the performance stack test. Sources that use CO and oxygen CEMS are not required to perform initial CO performance testing nor are they subject to oxygen content operating limit requirements. Sources that choose to demonstrate continuous compliance by monitoring and complying with an oxygen content operating limit must install, operate, and maintain an oxygen analyzer system at or above the minimum percent oxygen by volume that is established as the operating limit for oxygen when firing the fuel or fuel mixture utilized during the most recent CO performance stack test. We have removed the requirement that the oxygen monitor be located at the outlet of the boiler, so that it can be located either within the combustion zone or at the outlet as a flue gas oxygen monitor.

We are amending the oxygen monitoring requirements to allow for the use of oxygen trim systems and have included oxygen trim systems in the definition of "oxygen analyzer system." We have clarified that operation of oxygen trim systems to meet the oxygen monitoring requirements shall not be done in a manner that compromises furnace safety. The definitions of "oxygen analyzer system" and "oxygen trim system" in 40 CFR 63.11237 read as follows:

- *Oxygen analyzer system* means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location. This definition includes oxygen trim systems.

- *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 carbon monoxide monitor that

automatically provides a feedback signal to the combustion air controller.

2. Tune-Up Standards

The EPA is amending the requirements for demonstrating continuous compliance with the work practice and management practice tune-up standards in 40 CFR 63.11223 to clarify that CO measurements that are required before and after tune-up adjustments may be taken using a portable CO analyzer. We are clarifying that the requirements to inspect the burner and the system controlling the air-to-fuel ratio may be delayed until the next scheduled shutdown. We are also clarifying that units that produce electricity for sale may delay these inspections until the first outage, not to exceed 36 months from the previous inspection. In addition, we are clarifying that optimization of CO emissions should be consistent with any NO_x requirements to which the unit is subject. Finally, we are specifying for units that are not operating on the required date for a tune-up, the tune-up must be conducted within 30 days of startup.

3. Performance Testing Frequency

The EPA is amending 40 CFR 63.11220 to specify in paragraph (b) that the owner or operator of an affected boiler does not need to conduct further PM emissions testing if, when demonstrating initial compliance with the PM emission limit, the performance test results show that the PM emissions are equal to or less than half of the PM emission limit. The owner or operator must continue to comply with all applicable operating limits and monitoring requirements. If the initial performance test results show that the PM emissions are greater than half of the PM emission limit, the owner or operator must conduct subsequent performance tests as specified in 40 CFR 63.11220(a).

We are clarifying in 40 CFR 63.11220(d) that existing affected boilers that have not operated since the previous compliance demonstration must complete their subsequent compliance demonstration no later than 180 days after the re-start of the affected boiler.

4. Fuel Analysis

The EPA is amending 40 CFR 63.11220 to specify in paragraph (c) that the owner or operator of an affected coal-fired boiler does not need to conduct further fuel analysis sampling if, when demonstrating initial compliance with the Hg emission limit, the Hg constituents in the fuel or fuel

mixture are measured to be equal to or less than half of the Hg emission limit. The owner or operator must continue to comply with all applicable operating limits and monitoring requirements.

When demonstrating initial compliance with the Hg emission limit, if the Hg constituents in the fuel or fuel mixture are greater than half of the Hg emission limit, the owner or operator must conduct quarterly sampling.

5. Averaging Times

The EPA is amending the averaging time for parameter monitoring and compliance with operating limits to a 30-day rolling average.

The EPA is revising the definitions of “30-day rolling average” and “daily block average” to exclude periods of startup and shutdown and periods when the unit is not operating in the calculation of the arithmetic mean.

6. Monitoring Data

The EPA is clarifying in 40 CFR 63.11221 the monitoring data collection requirements.

J. Periods of Startup and Shutdown

1. Definitions

The EPA is revising the definitions of “startup” and “shutdown” such that they are tailored for industrial boilers and are consistent with the definitions of “startup” and “shutdown” in the 40 CFR part 63, subpart A General Provisions. The revised definitions reflect the fact that industrial boilers function to provide steam or, in the case of cogeneration units, electricity. We are defining startup as the period between either the first-ever firing of fuel in the boiler or the firing of fuel in the boiler after a shutdown and when the boiler first supplies steam or heat. We are defining shutdown as the period between either when no more steam or heat is supplied by the boiler or no fuel is being fired in the boiler and when there is no steam and no heat being supplied and no fuel being fired in the boiler.

2. Compliance With Operating Limits

The EPA has clarified that operating limits must be met at all times except during periods of startup and shutdown.

3. Minimization of Startup and Shutdown Periods

The EPA is amending 40 CFR 63.11223(g) to include biomass- and oil-fired boilers in the requirement to minimize the time spent in startup and shutdown periods. Specifically, the requirement is to minimize the boiler’s startup and shutdown periods and conduct startups and shutdowns

according to the manufacturer’s recommended procedures. If manufacturer’s recommended procedures are not available, recommended procedures for a unit of similar design for which manufacturer’s recommended procedures are available must be followed.

K. Affirmative Defense Language

In this final rule, the EPA is updating the affirmative defense provisions for malfunctions that were included in the March 21, 2011, final rule. We have made certain changes to 40 CFR 63.11226 to clarify the circumstances under which a source may assert an affirmative defense. The changes clarify that a source may assert an affirmative defense to a claim for civil penalties for violations of standards that are caused by malfunctions. A source can avail itself of the affirmative defense when there has been a violation of the emission standards due to an event that meets the definition of malfunction under 40 CFR 63.2 and qualifies for assertion of an affirmative defense under 40 CFR 63.11226. In the March 2011 final rule, we used terms such as “exceedance” or “excess emissions” in 40 CFR 63.11226, which created unnecessary confusion as to when the affirmative defense could be used. In this final 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 criteria for the assertion of an affirmative defense under 40 CFR 63.11226.

This final rule requires that to establish the affirmative defense the owner must prove by a preponderance of evidence that repairs were made as expeditiously as possible when a violation occurs. We have re-evaluated the language concerning the use of off-shift and overtime labor, to the extent practicable, to make the repairs and believe that the language is not necessary. Thus, the language has been eliminated from this final rule.

We have also eliminated the 2-day notification requirement that was included in 40 CFR 63.11226(b) of the March 2011 final rule because we expect to receive sufficient notification of malfunction events that result in violations in other required compliance reports as specified under 40 CFR 63.11225. In addition, we have revised the 45-day affirmative defense reporting requirement that was included in 40 CFR 63.11226(b) of the March 2011 final rule. This final rule requires 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 30-day extension for submitting a stand-alone affirmative defense report. Consequently, we are not including that provision in this final rule.

L. Notification, Recordkeeping and Reporting Requirements

The EPA is amending 40 CFR 63.11225(a)(2) to specify that existing affected boilers have until January 20, 2014 to submit their Initial Notification.

The EPA is amending 40 CFR 63.11225(c)(2) to specify that records of fuel use and type are required only for boilers that are subject to numerical emission limits. We are also amending 40 CFR 63.11223(b) to clarify that the type and amount of fuel needs to be included in reports only if the boiler was physically and legally capable of using more than one type of fuel during that time period and that the report should include concentrations of CO and oxygen, measured at high fire or typical operating load, before and after the tune-up of the boiler. Finally, we are specifying that for units sharing a fuel meter, the fuel use by each boiler may be estimated.

The EPA is amending 40 CFR 63.11225(b) to clarify the requirements for submitting a biennial or 5-year report for units that are only subject to tune-up requirements and to specify the information that must be included in the annual, biennial, or 5-year compliance report.

We are amending 40 CFR 63.11225(c)(2) to specify, as applicable, that a copy of the energy assessment, records documenting the days of operation for each boiler that meets the definition of a seasonal boiler, and a copy of the federally enforceable permit for each boiler that meets the definition of a limited-use boiler must be maintained.

We are revising 40 CFR 63.11225(d) to remove the requirement that the most recent 2 years of records be maintained on site and are adding language that allows for computer access or other means of immediate access of records stored in a centralized location.

We are adding a new paragraph 40 CFR 63.11225(g) to require that boilers that switch fuels, make a physical change, or take a permit limit that results in the applicability of a different subcategory within subpart JJJJJJ, a switch out of subpart JJJJJJ, or the applicability of subpart JJJJJJ must provide notification within 30 days of the fuel switch, physical change, or permit limit. 40 CFR 63.11225(g) also specifies what information the notification must include.

M. Title V Permitting Requirements

For the reasons stated in our March 21, 2011, final rule (76 FR 15554) as well as our reconsideration proposal (76 FR 80532, December 23, 2011), the EPA is not making any changes to the title V exemption for area sources. Thus, no area sources subject to subpart JJJJJJ are required to obtain a title V permit as a result of being subject to subpart JJJJJJ.

Facilities that are synthetic area sources for HAP under subpart JJJJJJ may already be covered by a title V permit or may be required to obtain a title V permit in the future for a reason other than subpart JJJJJJ. For example, area source boilers could be major sources of non-HAP pollutants or could be located at sources that are subject to title V. Thus, the title V exemption in subpart JJJJJJ does not affect whether or not these area sources under subpart JJJJJJ are otherwise required to obtain a permit under part 70 or part 71. See 40 CFR 70.3(a) and (b) or 71.3(a) and (b).

N. Definition of Period of Gas Curtailment or Supply Interruption

We are amending the definition of “period of natural gas curtailment or supply interruption” in 40 CFR 63.11237 to clarify that a curtailment does not include normal market fluctuations in the price of gas that are not associated with periods of supplier delivery restrictions. We are also amending the definition to indicate that periods of supply interruption that are beyond control of the facility can also include on-site natural gas system emergencies and equipment failures, and that legitimate periods of supply interruption are not limited to off-site circumstances. We are revising the term and the definition so that it includes the curtailment of any gaseous fuel, and is not limited to just natural gas. Finally, we are clarifying that the supply of gaseous fuel is to an “affected boiler” rather than “affected facility” and that the supply of gaseous fuel is “restricted or halted” for reasons beyond the control of the facility. The definition is amended to read as follows:

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler 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.

O. Miscellaneous Technical Corrections

In addition to the above summary of the EPA’s final action regarding provisions identified for reconsideration and on other discrete matters identified in response to comments or data received during the comment period, other definitional and regulatory text revisions are being made. These clarifications will help affected sources determine their applicability and better understand the rule requirements. In some instances, definitions and regulatory text have been revised or added to correspond with other related rules, especially the emission standards for industrial, commercial, and institutional boilers at major sources of HAP (40 CFR part 63, subpart DDDDD). Section IV of this preamble includes additional details regarding these miscellaneous technical corrections.

P. Other Issues

40 CFR 63.11196(a)(1) of the March 21, 2011, final rule (76 FR 15554) requires that owners and operators of existing affected boilers subject to the tune-up requirement complete the initial boiler tune-up by March 21, 2012. In addition, 40 CFR 63.11225(a)(4) requires that owners and operators of existing affected boilers subject to the tune-up requirement submit their Notification of Compliance Status no later than 120 days after the applicable compliance date specified in 40 CFR 63.11196. That means that those owners and operators were required to submit their Notification of Compliance Status by July 19, 2012. The Notification must include, among other information, a certification that states “This facility complies with the requirements in § 63.11214 to conduct an initial tune-up of the boiler.”

On March 13, 2012, the EPA issued a No Action Assurance (NAA) to all owners and/or operators of existing industrial boilers and commercial and

institutional boilers at area sources of HAP emissions stating that we would not enforce the requirement to conduct an initial tune-up by March 21, 2012. The NAA was primarily based upon the EPA’s concern that sources were reporting a shortage of qualified individuals to prepare boilers for tune-ups and then conduct those tune-ups by the regulatory deadline, as well as upon the uncertainty in the regulated community resulting from the pending reconsideration of the Area Source Boiler Rule. The March 13, 2012, NAA states that it remains in effect until either (1) 11:59 p.m. EDT, October 1, 2012, or (2) the effective date of a final rule addressing the proposed reconsideration of the Area Source Boiler Rule, whichever occurs earlier.

As the July 19, 2012, Notification of Compliance Status deadline approached, a final rule addressing the proposed reconsideration of the Area Source Boiler Rule had not been issued, and thus the NAA continued to remain in effect. Nothing that the EPA learned since the issuance of the original NAA letter led us to question our original concerns about the feasibility of all sources timely completing an initial tune-up. Further, sources that did not complete a tune-up could not certify that they conducted one. Thus, on July 18, 2012, the EPA extended the NAA for sources required to complete an initial tune-up by March 21, 2012, to also include the deadline for submitting the Notification of Compliance Status regarding the initial tune-up. In addition, given that no final rule addressing the proposed reconsideration of the Area Source Boiler Rule had been issued as of July 18, 2012, the pending reconsideration continued to create uncertainty in the regulated community. Thus, the NAA letter also amended the expiration date of the March 13, 2012, NAA, such that the NAA would remain in effect until either (1) 11:59 p.m. EST, December 31, 2012, or (2) the effective date of a final rule addressing the proposed reconsideration of the Area Source Boiler Rule, whichever occurs earlier.

This final rule revises the compliance date for existing affected boilers subject to a tune-up from March 21, 2012, to March 21, 2014. The July 19, 2012, deadline for submitting the Notification of Compliance Status regarding the initial tune-up is reset to July 19, 2014, as a result of revising the compliance date for existing affected boilers subject to a tune-up to March 21, 2014. Owners or operators that had not yet conducted their boiler tune-up, but submitted a Notification of Compliance Status by July 19, 2012, simply to notify the EPA

that the tune-up had not been completed, will need to submit a revised Notification of Compliance Status after their boiler tune-up is conducted.

IV. Summary of Significant Changes Since Proposed Action on Reconsideration

Numerous changes are being made to the March 2011 final rule based on the public comments received. Most of the changes are editorial 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 “Summary of Public Comments and Responses for: National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers” located in the docket.

A. Applicability

Since proposal, changes to the applicability of this final rule have been made.

1. Dual-Fuel Fired Boilers

The March 2011 final rule includes as a new affected source a boiler that commences fuel switching from natural gas to solid fossil fuel, biomass, or liquid fuel after June 4, 2010. For example, under the March 2011 final rule, if an unaffected gas-fired boiler currently burns oil as allowed under the definition of gas-fired boiler, but after June 4, 2010 burns oil for reasons not allowed under the definition of gas-fired, these boilers would become new affected oil-fired units. The December 2011 reconsideration action did not propose any revisions to the provisions regarding boilers that fuel switch after June 4, 2010. However, the EPA has been made aware through public comments that many dual-fuel fired units presently burn primarily natural gas with limited or no amounts of oil, and that these units may want to burn oil in the future for reasons not allowed under subpart JJJJJ’s definition of gas-fired (e.g. cost). Under the March 2011 final rule, such an existing dual-fuel gas-fired boiler that wanted to avoid being subject to the new source requirements would notify as an existing oil-fired unit and be subject to the requirements for existing oil-fired boilers.

We received public comments regarding rule applicability and compliance requirements for these existing dual-fuel fired boilers. One commenter asserted that regardless of the fuel capability identified in an

initial notification, the distinction between a new source and an existing source should only be made based upon a source’s capability to burn a particular fuel as of the effective date of the rule. The commenter explained that many facilities have boilers that can burn either gas or liquid and, because the price of gas is currently lower than the price of most liquid fuels, they likely are currently firing gas during normal operation, with liquid being fired only during periods of curtailment. The commenter pointed out that, in the future, the price of liquid fuel may be lower than the price of gaseous fuel, and facilities may want to preferentially burn liquid fuel over gas fuel. The commenter asserted that a change in the fuel from the initial notification should not, in and of itself, reclassify a source as a new source for purposes of subpart JJJJJ. Further, the commenter asserted that their interpretation is comparable to the fuel switching provisions in the EPA’s NSPS and PSD regulations. The same commenter asserted that if a source already has oil or alternate fuel capability, then that source would not be commencing construction or making a change to the source. The commenter explained that many of these facilities with boilers capable of burning fuel oil as a back-up for natural gas may not have submitted an initial notification since gaseous fuel-fired boilers that only burn liquid during periods of curtailment are not covered by the Area Source Boiler Rule. The commenter maintained the EPA’s guidance, that a dual-fuel fired boiler that fails to file an initial notification and then plans to burn oil in the future would be considered to be a new source, appears to be contrary to regulatory text stating that an affected source is a new source if construction or reconstruction of the affected source is commenced after June 4, 2010 and the applicability criteria are met at the time construction is commenced. The commenter suggested that the EPA clarify that to become a new source, the source must be altered to be capable of accommodating a new fuel, so that new sources are not created simply by failing to submit an initial notification or a notice of fuel switching for a unit that is already capable of accommodating that fuel. Another commenter explained that owners and operators of dual-fuel fired boilers anticipate firing natural gas for many years to come, or until gas supply is temporarily curtailed outside of their control or until such a time when fuel oil becomes more cost effective to burn than gas. The commenter asserted that, based on common sense and increased

flexibility, these dual-fuel fired boilers normally burning gas could not be considered subject to any oil-fired requirements as long as they continue to fire only gas, except under the regulation’s stated exemptions for burning oil.

In addition to carefully considering the public comments received regarding dual-fuel fired boilers, the EPA reconsidered its overall intent with regard to existing dual-fuel fired boilers that fuel switch after June 4, 2010. Consequently, in this final rule, we are revising the provisions regarding existing boilers that fuel switch after June 4, 2010. This final rule amends 40 CFR 63.11194 to specify that an existing dual-fuel fired boiler (*i.e.*, commenced construction or reconstruction on or before June 4, 2010) meeting the definition of gas-fired boiler, as defined in 40 CFR 63.11237, that meets the applicability requirements of subpart JJJJJ after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be an existing source under this subpart as long as the boiler was designed to accommodate the alternate fuel. A new or reconstructed dual-fuel fired boiler (*i.e.*, commenced construction or reconstruction after June 4, 2010) meeting the definition of gas-fired boiler, as defined in 40 CFR 63.11237, that meets the applicability criteria of subpart JJJJJ after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be a new source under this subpart. This revision maintains consistency with the rule’s applicability criteria for determining new versus existing sources, eliminates the requirement that existing dual-fuel fired boilers notify as affected sources although, at the time, they are not subject to subpart JJJJJ, and promotes flexibility in that these existing dual-fuel fired sources that were designed to accommodate an alternate fuel may fire the alternate fuel and move into subpart JJJJJ without being subject to the more stringent requirements for new boilers.

2. Residential Boilers

One commenter suggested that the definition of “residential boiler,” as proposed, be revised to acknowledge the use of combined heat and power systems which function with heat and/or hot water systems. The EPA agrees and is amending the proposed definition to clarify that a boiler that operates as part of a residential combined heat and power system (and that meets other definitional requirements) is a residential boiler. Another commenter explained that

historical buildings may be subdivided into more than four units but boilers serving those units should still be considered residential boilers. We agree and, in this final rule, are amending the proposed definition to clarify that a boiler serving a single unit residence dwelling that has since been converted or subdivided into condominiums or apartments may also be considered a residential boiler.

3. Temporary Boilers

One commenter supported the EPA's 12-month threshold above which the boiler would no longer be considered temporary but pointed out that a boiler used on a temporary basis during construction of a commercial building may be needed for more than 12 months due to the length of the construction period. The commenter suggested that the definition of temporary boiler, as proposed, be revised to allow owners or operators to petition for an extension beyond 12 months. We agree with the commenter and, in this final rule, are amending the proposed definition to allow an owner or operator to submit to their regulatory agency a petition for an extension beyond 12 months. Another commenter suggested that the EPA expand on the intent of "location" in the definition of "temporary boiler." We are amending the proposed definition to clarify that "location" means "location within the facility." This clarification will allow a boiler to be moved from one location to another within a facility and be considered a different temporary boiler (*i.e.*, a new time period begins) as long as the boiler does not continue to perform the same or similar function and to serve the same electricity, steam, and/or hot water system. Another commenter pointed out that our definition, as proposed, does not specify a time period associated with the statement "Any temporary boiler that replaces a temporary boiler at a location within the facility and performs the same or similar function will be included in calculating the consecutive time period." The commenter explained that it is not unusual for a temporary boiler to be used for short periods during turnarounds or other maintenance activities that recur several years apart. Under the proposal, these boilers would not be considered temporary because each boiler replaces the previous one and performs the same function, even though there is a multi-year gap between the occurrences. The commenter suggested that replacements that occur after a gap of at least one year should not be considered consecutive for the purposes of the definition. We agree with the commenter and are

amending numbered paragraph (2) in the proposed definition of "temporary boiler" such that it specifies that "Any temporary boiler that replaces a temporary boiler at a location within the facility and performs the same or similar function will be included in calculating the consecutive time period *unless there is a gap in operation of 12 months or more.*"

4. Seasonal Boilers

Several commenters explained that boilers subject to semi-annual testing requirements would not meet the proposed 7 consecutive month shutdown criteria, but otherwise would be considered seasonal boilers. Commenters suggested that seasonal boiler be defined to allow periodic testing during the 7-month shutdown period. We agree with the commenters and, in this final rule, are revising the proposed definition of seasonal boiler to allow for a combined total of 15 days of use during the shutdown period for periodic testing.

Another commenter pointed out that the EPA's seasonal boiler definition, as proposed, would potentially allow more regular use. The commenter specifically suggested that the proposed definition be revised to clarify that there must be a 7 consecutive month shutdown every 12 months. It was the EPA's intent that the shutdown period of at least 7 consecutive months be on a 12-month basis. In response to this comment, we are clarifying in the definition of seasonal boiler that the shutdown must be for a period of at least 7 consecutive months (or 210 consecutive days) each 12-month period.

5. Limited-Use Boilers

Several commenters asserted that the EPA should also include a limited-use subcategory in the area source rule for the same reasons we determined a seasonal boiler subcategory was appropriate. Commenters suggested that we should apply the same 5-year tune-up cycle for limited-use units such as auxiliary boilers that we proposed for seasonally-operated units and small oil-fired units. Commenters explained that in the electric utility industry, auxiliary boilers are typically used to generate the steam necessary to bring a main EGU on line during startup and, since auxiliary boilers are primarily operated during unit startup, operation for many of these boilers is typically very limited and sporadic. Commenters also pointed out that the Major Source Boiler Rule includes a limited-use subcategory.

The EPA has determined that a limited-use subcategory is appropriate and is including a limited-use

subcategory in this final Area Source Boiler Rule. Specifically, a limited-use boiler is defined in this final rule to mean any boiler that burns any amount of solid or liquid fuels and has a federally enforceable average annual capacity factor of no more than 10 percent. We are using a capacity-factor approach for the same reasons that the approach is being used in the Major Source Boiler Rule. A capacity-factor approach allows operational flexibility for units that operate on standby mode or low loads for periods longer than would be allowed under an approach that limited hours of operation (*e.g.*, the 876 hours per year included in the proposed limited-use definition for major source boilers). The operational flexibility associated with a capacity-factor approach can be achieved without increasing emissions or harm to human health and the environment. 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 test these limited-use boilers since these units serve as back-up energy sources and their operating schedules can be intermittent and unpredictable.

This final rule specifies that limited-use boilers are required to complete a tune-up every 5 years. Boilers that operate no more than 10 percent of the year (*i.e.*, a limited-use boiler) would operate for no more than 6 months in between tune-ups on a 5-year tune-up cycle. The brief period of operations is even less than the number of operating months that seasonal boilers and full-time boilers will operate between tune-ups. The irregular schedule of operations also makes it difficult to schedule more frequent tune-ups. We believe that establishing a limited-use subcategory is reasonable.

6. Alternative PM Emission Control for Certain Oil-Fired Boilers

The EPA received a number of comments urging that we provide an exemption from the PM limit for units burning low-sulfur liquid fuel as is provided in subpart Dc of 40 CFR part 60 (standards of performance for new small industrial-commercial-institutional steam generating units). Commenters asserted that such an exemption is justified since the low sulfur content indicates low PM emissions and that boilers firing low-sulfur liquid fuel should only be subject to a requirement to maintain records documenting the liquid fuel fired. We agree burning low-sulfur liquid fuel can be an alternative method of meeting GACT for PM. We are amending 40 CFR

63.11210 to specify that new or reconstructed oil-fired boilers that combust only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM emission limit under this subpart and that do not use a post-combustion technology (except a wet scrubber) to reduce PM or sulfur dioxide emissions meet GACT for PM providing the type of fuel combusted is monitored and recorded on a monthly basis. Further, we are specifying that if you intend to burn a new type of fuel or fuel mixture that does not meet the requirements of this paragraph, you must conduct a performance test within 60 days of burning the new fuel.

B. Tune-Up Requirements

1. Boilers With Oxygen Trim Systems

In this final rule, the EPA is adding to the types of boilers that must conduct a tune-up every 5 years boilers that have an oxygen trim system that maintain an optimum air-to-fuel ratio that would otherwise be subject to biennial tune-ups. These units do not need to be tuned as frequently as other types of boilers because the trim system is designed to maintain an optimum air-to-fuel ratio which is the purpose of a tune-up.

2. Initial Compliance for Existing Boilers

The EPA is revising the initial compliance date for existing boilers subject to the work practice or management practice standard of a tune-up. Under the proposed rule, owners and operators of existing affected boilers would have had to comply with the final rule by March 21, 2013. We solicited comments on whether to extend the compliance date to March 21, 2014. We received no comments objecting to either of these dates. Support for an extension until 2014 came from a variety of stakeholders affected by the rule. Therefore, this final rule requires that if you own or operate an existing boiler subject to a work practice or management practice standard of a tune-up, you must comply with the final rule no later than March 21, 2014.

3. Compliance Demonstration

We solicited comment on the requirements for demonstrating compliance with the work practice and management practice tune-up standards, with one focus on clarifying how to measure CO. Commenters requested that we clarify that CO measurements may be taken with a portable CO analyzer.

We agree that this clarification is appropriate and are including this clarification in this final rule.

C. Energy Assessment

The EPA received a number of comments regarding the energy assessment requirements and in this final rule is making a series of changes to the energy assessment provisions and related definitions that clarify terms used and better set the scope of the assessment.

In this final rule, we are revising the definition of energy assessment by providing a duration for performing the energy assessment for numbered paragraph (3) in the definition of “energy assessment” in 40 CFR 63.11237 for facilities with units with greater than 1 TBtu/yr heat input capacity to specify time duration/size ratio and are including a cap to the maximum number of on-site technical hours that should be used in the energy assessment. The energy assessment for facilities with affected boilers and process heaters with greater than 1.0 TBtu/yr heat input capacity will be up to 24 on-site technical labor hours in length 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, which could vary significantly depending on the site and its complexity, and not by a total aggregation of all individual energy using elements of a facility. We are adding the following language, as paragraph (4), to the “energy assessment” definition to help resolve current problems and allow for more streamlined assessments:

“(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) energy output 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).”

In this final rule, we are revising 40 CFR 63.11201 and Table 2 to subpart JJJJJJ to allow a source that is operating under an energy management program established through energy management systems compatible with ISO 50001, that includes the affected boilers, by March 21, 2014, to satisfy the energy assessment requirement. In addition, we are clarifying that energy assessor

approval and qualification requirements are waived in instances where an energy assessment completed on or after January 1, 2008 meets or is amended to meet the energy assessment requirements in this final rule by March 21.

The definition of “boiler system” is being revised in this final rule to clarify that it means the boiler and associated components directly connected to and serving the energy use systems.

The definition of “energy use system” is also being revised in this final rule to clarify that energy use systems are only those on-site systems using energy clearly produced by affected boilers.

D. Clarification of Oxygen Concentration Operating Limits

We are clarifying in this final rule that operating limits for oxygen concentration must be at or above the minimum established during a performance stack test. We are also clarifying that these limits are applicable when the unit is firing the fuel or fuel mixture utilized during the CO performance test.

E. Definitions Regarding Averaging Times

The EPA received comments requesting that we clarify that periods of startup and shutdown are excluded from calculation of the arithmetic mean in the definitions of “30-day rolling average” and “daily block average.” We agree with the commenters and, in this final rule, are revising the definitions accordingly.

F. Fuel Sampling Frequency

The EPA is amending the fuel sampling requirements in 40 CFR 63.11220(c) because we realized that when performance stack testing requirements were revised in the March 2011 final rule we neglected to revise the fuel analysis requirements. In this final rule, we are specifying that the owner or operator does not need to conduct further fuel analysis sampling if, when demonstrating initial compliance with the Hg emission limit, the Hg constituents in the fuel or fuel mixture are measured to be equal to or less than half of the Hg emission limit. If, when demonstrating initial compliance, the Hg constituents in the fuel or fuel mixture are greater than half of the Hg emission limit, the owner or operator must conduct quarterly sampling.

G. Performance Testing Frequency

The EPA is amending the PM performance testing requirements in 40 CFR 63.11220(b) to specify that the

owner or operator of an affected boiler does not need to conduct further PM emission testing if, when demonstrating initial compliance with the PM emission limit, the performance test results show that the PM emissions are equal to or less than half of the PM emission limit. The owner or operator must continue to comply with all applicable operating limits and monitoring requirements. If the initial performance test results show that the PM emissions are greater than half of the PM emission limit, the owner or operator must conduct subsequent performance tests as specified in 40 CFR 63.11220(a).

With respect to the reconsideration issue regarding the GACT-based PM standards for new oil-fired boilers, we received comments asserting that the most effective control strategy for small oil-fired boilers is the tune-up required by the standards and that establishing a PM limit for those boilers between 10 MMBtu/hr and 30 MMBtu/hr just ensures that those boilers will do stack testing demonstrating that the boilers are in compliance without the need for controls; a fact already known. Commenters also asserted that establishing a PM limit imposes a stack test obligation on small facilities with the least resources to deal with the testing.

We have reviewed the comments and are not eliminating or revising the PM limit for new oil-fired boilers with heat input capacity between 10 MMBtu/hr and 30 MMBtu/hr. We do however, believe that adjustments to the PM performance test frequency as described above are appropriate for boilers that demonstrate during their initial performance test that their PM emissions are equal to or less than half of the PM limit. We believe that the performance test adjustment should not be potentially applicable to only new oil-fired boilers with heat input capacity between 10 MMBtu/hr and 30 MMBtu/hr, but to all new boilers. Owners or operators of boilers whose initial performance test results show that their PM emissions are equal to or less than half of the PM emission limit and, thus, do not need to conduct further PM emissions testing, must continue to comply with all applicable operating limits and monitoring requirements to ensure that there are no changes in operation of the boiler or air pollution control equipment that could increase emissions. This adjustment in PM performance test frequency will potentially reduce the burden on small entities operating boilers that meet the adjustment criteria.

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 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 definitions 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 subject to applicable standards at all times steam of the proper pressure, temperature and flow rate is being provided 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 this final rule as follows:

Startup means either the first-ever firing of fuel in a boiler 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 is supplied for heating and/or producing electricity, or for any other purpose.

Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam or heat 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, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler.

I. Notifications

1. Initial Notification

The EPA has been made aware that there are many affected boilers at area sources that are just becoming aware, or are not yet aware, that they are subject to emission standards. Thus, we are amending 40 CFR 63.11225(a)(2) to allow these sources until January 20, 2014 to submit their Initial Notification.

2. Notification of Fuel Change, Physical Change, or Permit Limit

The notification requirement in 40 CFR 63.11225(g) of the final rule for instances when a change in fuel or a physical change to a boiler results in the applicability of a different subcategory or a change out of subpart JJJJJJ is being revised. Under the proposed reconsideration action, a facility would have been required to provide 30 days prior notice of the date upon which the change was scheduled to occur. Commenters explained that an advanced notification requirement would delay such a change if the owner or operator decided to immediately make a change (*e.g.*, switch to 100 percent natural gas) and could potentially restrict flexibility in manufacturing operations, and suggested that the owner or operator be allowed to make notification within 30 days after the change has occurred. We agree that notification within 30 days after a change that results in applicability of a different subcategory or a change out of subpart JJJJJJ will provide the EPA or state/local agency with the required information within a reasonable timeframe. Thus, in this final rule, we are requiring facilities making these types of changes to provide notification within 30 days following the change. The notification requirement in 40 CFR 63.11225(g) is also being amended to clarify that it includes affected boilers that switch fuels or make a physical change to the boiler and the fuel switch or change results in the applicability of a different subcategory within subpart JJJJJJ, in the boiler becoming subject to subpart JJJJJJ, or in the boiler switching out of subpart JJJJJJ due to a change to 100 percent natural gas, as well as affected boilers that take a permit limit that results in the applicability of subpart JJJJJJ. Commenters requested that we make this clarification and we agree that it is appropriate.

J. Miscellaneous Definitions

In this final rule, we are revising some definitions and adding others to help affected sources determine their applicability. Specifically, definitions have been added for the terms “10-day rolling average,” “30-day rolling average,” “Annual heat input,” “Biodiesel,” “Calendar year,” “Common stack,” “Daily block average,” “Distillate oil,” “Electric boiler,” “Electric utility steam generating unit (EGU),” “Energy management program,” “Fluidized bed boiler,” “Fluidized bed combustion,” “Hourly average,” “Limited-use boiler,” “Load fraction,”

“Minimum scrubber pressure drop,” “Minimum sorbent injection rate,” “Minimum total secondary electric power,” “Operating day,” “Oxygen analyzer system,” “Oxygen trim system,” “Process heater,” “Regulated gas stream,” “Residential boiler,” “Residual oil,” “Seasonal boiler,” “Shutdown,” “Solid fuel,” “Startup,” “Temporary boiler,” “Tune-up,” “Vegetable oil,” “Voluntary Consensus Standards (VCS),” and “Wet scrubber.”

Definitions revised to clarify the term include “Bag leak detection system,” “Biomass subcategory,” “Boiler,” “Boiler system,” “Deviation,” “Dry scrubber,” “Electrostatic precipitator (ESP),” “Energy assessment,” “Energy use system,” “Federally enforceable,” “Gas-fired boiler,” “Heat input,” “Hot water heater,” “Institutional boiler,” “Liquid fuel,” “Minimum activated carbon injection rate,” “Minimum oxygen level,” “Minimum scrubber liquid flow rate,” “Natural gas,” “Oil subcategory,” “Particulate matter,” “Period of gas curtailment or supply interruption,” “Qualified Energy Assessor,” and “Waste heat boiler.”

V. Other Actions the EPA Is 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 of five

issues because this criterion has not been met. In many cases, the petitions reiterate comments made on the proposed June 2010 rule during the public comment period for that rule. On those issues, the EPA responded to those comments in the March 2011 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 50, 58 (DC Cir. 1984) and *International Fabricare Institute v. EPA*, 972 F.2d 384, 399 (DC 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 (DC 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 (DC 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 five 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: Use of RDL Is Unlawful

The petitioner (Sierra Club) objected to the EPA establishing a MACT floor emission limit at a level equal to three times the RDL as being unlawful and arbitrary. This issue is not of central relevance to the outcome of this final rule. The final emission limits in this rule are based on the UPL at a confidence interval of 99 percent. The RDL analysis was not used in this final rule.

Issue: MACT Floor for Existing Sources Must Reflect Average Performance of the Top 12 Percent of Units

The petitioner (Sierra Club) stated that the MACT floor for existing sources must reflect the average performance of the top 12 percent of units. The petitioner has not demonstrated that it lacked the opportunity to comment on the EPA’s MACT floor analysis. The methods used to compute the MACT floors were subject to notice and comment. Rationale and responses to comments on the MACT floor methodology were provided at 75 FR 31904, June 4, 2010; 76 FR 15571, March 21, 2011. Therefore, the EPA is denying the request for reconsideration.

Issue: Consider a De Minimis Size Threshold

The petitioners (American Petroleum Institute, National Petrochemical and Refiners Association, Alaska Oil and Gas Association) requested that the EPA consider a de minimis size threshold using guidelines from insignificance thresholds authorized under CAA part 71. The EPA is denying the request for reconsideration on this issue. In the June 2010 proposed rule, it was readily apparent that we were not establishing de minimis size thresholds in the area source rulemaking. We received multiple comments on this issue and responded to them in the response to comments document for the March 2011 final rule. The issue on which petitioners seek reconsideration was one that could have been raised during the comment period and thus does not meet the requirements for reconsideration. Therefore, the EPA is denying this request for reconsideration.

Issue: MACT Standards Must Be Set for All HAP

The petitioner (Sierra Club) asserted that MACT standards must be set for all HAP including HAP not listed in CAA section 112(c)(6). The EPA is denying the request for reconsideration on this issue. We disagree with the petitioner that the EPA must issue emission standards for all HAP. MACT standards have been set for Hg and CO, as a

surrogate for POM emissions, but the EPA does not interpret CAA section 112(c)(6) to compel regulation of all HAP emitted by area sources. The EPA's position on this issue was clear in the proposed rule (75 FR 31900, 31904, 31918). This commenter raised this issue in its comments (76 FR 15567, March 21, 2011). Not only did the petitioner have an opportunity to present its theory in its comments, but also it did so.

Issue: CO Is Not a Valid Surrogate for POM

The petitioner (Sierra Club) requested that the EPA remove the CO standard as a surrogate for POM and instead adopt a numeric limit for POM 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 POM, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA revised the final CO emission limit to ensure a more accurate correlation between POM and CO levels. The EPA made its position on this issue clear and explained the agency's basis for concluding that CO was an appropriate surrogate in the proposed rule (75 FR 31900, 31904, June 4, 2010). The petitioner raised this issue in its comments (Document ID: EPA-HQ-OAR-2006-0790-1982, Comments of Earthjustice, Sierra Club, Clean Air Task Force, and Natural Resources Defense Council, p. 4). Therefore, the EPA is denying the request for reconsideration.

VI. Impacts Associated With This Final Rule

The amendments contained in this final action are corrections that are intended to clarify, but not change, the coverage of the final rule. The clarifications and corrections should make it easier for owners and operators and for local and state authorities to understand and implement the requirements. The final amendments will not affect the estimated emission reductions, control costs or the benefits of the rule in substance. The amendments do not impose any additional regulatory requirements beyond those imposed by the previously promulgated boiler area source rule and, in fact, will result in a decrease in the burden on small facilities as a result of the reduction in the frequency of conducting tune-ups for seasonal boilers, limited-use boilers, small (equal to or less than 5 MMBtu/hr) oil-fired boilers and boilers using an oxygen trim system that maintain an optimum air-to-

fuel ratio. Additionally, the burden will be reduced on facilities with existing large boilers that currently operate under an energy management program established through energy management systems compatible with ISO 50001, that includes the affected boilers, because a one-time energy assessment will not be required. Burden will also be reduced on facilities with affected boilers that burn low-sulfur oil because, in lieu of needing to meet an emission limit, we consider low-sulfur oil combustion to be GACT for PM for those boilers. This change should allow sources currently complying with 40 CFR 60 subpart Dc to use the same compliance approach rather than needing to monitor limits. Further reduction in burden will occur in instances where initial compliance demonstrations with the Hg emission limit via fuel sampling or with the PM emission limit via performance stack testing show that the emissions are equal to or less than half the respective emission limit because no further sampling or testing of those boilers will be required.

As discussed in section III, the Hg emission limits for new and existing large (10 MMBtu/hr or greater) coal-fired area source boilers were revised because of an error discovered in the analysis conducted for the final rule. This technical correction resulted in an increase in the emission limit for Hg. As explained in the December 2011 proposal, we also revised our impacts analysis to be consistent with emission factor changes made to the Major Source Boiler Rule. The baseline emissions for area sources are calculated using the emission factors developed for the Major Source Boiler Rule because of insufficient data for area sources. Emission factor changes resulted in a higher baseline emission for Hg from coal-fired area source boilers. Consequently, the result of the increase in both baseline Hg emissions and Hg emission limits is that the overall reduction in Hg emissions does not change significantly from the estimated reduction for the promulgated rule.

In summary, as compared to the control costs estimated for the March 2011 final rule, this final rule will not result in any meaningful change in the capital and annual cost due to the increase in emission limits and the decrease in burden on small facilities.

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 a "significant regulatory action" because it is likely to raise novel legal or policy issues. Accordingly, the EPA submitted this action to the OMB for review under Executive Order 12866 and Executive Order 13563 (76 FR 3821, January 21, 2011), and any changes made in response to OMB recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

This action does not impose an information collection burden. This action results in no significant changes to the information collection requirements of the promulgated rule and will have no increased impact on the information collection estimate of projected cost and hour burden made and approved by OMB. In fact, the reduction in tune-up frequency for some boilers will result in less information collection burden. Therefore, the information collection request has not been revised. However, the OMB has previously approved the information collection requirements contained in the existing regulation (40 CFR part 63, subpart JJJJJ) under the provisions of the *Paperwork Reduction Act*, 44 U.S.C. 3501, *et seq.* and has assigned OMB control number 2060-0668. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

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.²

² Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impacts of this final rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration size standards for small businesses at 13 CFR 121.201 (less than 500, 750, or 1,000 employees, depending on the specific NAICS Code under subcategory 325); (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

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. section 605(c). These amendments and notice of final action on reconsideration are closely related to the final Area Source Boiler Rule, which the EPA signed on February 21, 2011, and that took effect on May 20, 2011. The EPA prepared a final regulatory flexibility analysis in connection with the final Area Source Boiler Rule. Therefore, pursuant to section 605(c), the EPA is not required to complete a final regulatory flexibility analysis for this rule (*i.e.*, the amendments and final action).

The EPA has been concerned with potential small entity impacts since it began developing the Area Source Boiler Rule. The EPA conducted outreach to small entities and, pursuant to section 609 of RFA, convened a Small Business Advocacy Review Panel (the Panel) on January 22, 2009, 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 final Area Source Boiler 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. Finally, we note that this action, which amends the Area Source Boiler Rule, will not impose any additional regulatory requirements beyond those imposed by the previously promulgated Area Source Boiler Rule and, in fact, the amendments will afford relief to some boilers.

D. Unfunded Mandates Reform Act

This action contains no new federal mandates under the provisions of Title II of the UMRA of 1995, 2 U.S.C. 1531–1538 for state, local, or tribal governments or the private sector. This action imposes no new enforceable duty on any state, local, or tribal governments or the private sector. Therefore, this action is not subject to the requirements of sections 202 and 205 of the UMRA.

This action is also not subject to the requirements of section 203 of UMRA

because it contains no regulatory requirements that might significantly or uniquely affect small governments. This rule finalizes amendments to aid with compliance.

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 new 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 new 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 Executive Order 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. We estimate no significant changes for the energy sector for price, production, or imports.

I. National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA of 1995, Public Law No. 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 OMB, explanations when the agency decides not use available and applicable VCS.

This action does not involve any new technical standards. Therefore, the EPA did not consider the use of any VCS.

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.

The EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because the level of protection provided to human health or the environment through the rule’s requirements does not vary. Therefore, it does not have any disproportionately high or adverse human health or environmental effects on any population, including any minority or low-income population.

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. The EPA will submit a report containing this 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

small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

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 reconsideration of a previous action that was a major rule under the CRA. However, today's action makes only certain limited revisions to the March 2011 rule and those revisions do not qualify as a major rule under the CRA. Therefore, this action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective February 1, 2013.

List of Subjects in 40 CFR Part 63

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

Dated: December 20, 2012.

Lisa P. Jackson,
Administrator.

For the reasons stated 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 citation for part 63 continues to read as follows:

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

Subpart A—[Amended]

- 2. 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 JJJJJ 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 JJJJJJ—[AMENDED]

■ 3. Section 63.11194 is amended by revising paragraphs (a)(1), (c) and (d), by redesignating paragraph (e) as paragraph (f) and by adding new paragraph (e) to read as follows:

§ 63.11194 What is the affected source of this subpart?

(a) * * *

(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers within a subcategory, as listed in § 63.11200 and defined in § 63.11237, located at an area source.

* * * * *

(c) An affected source is a new source if you commenced construction of the affected source after June 4, 2010, and the boiler meets the applicability criteria at the time you commence construction.

(d) An affected source is a reconstructed source if the boiler meets the reconstruction criteria as defined in

§ 63.2, you commenced reconstruction after June 4, 2010, and the boiler meets the applicability criteria at the time you commence reconstruction.

(e) An existing dual-fuel fired boiler meeting the definition of gas-fired boiler, as defined in § 63.11237, that meets the applicability requirements of this subpart after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be an existing source under this subpart as long as the boiler was designed to accommodate the alternate fuel.

* * * * *

■ 4. Section 63.11195 is amended by revising the introductory text and paragraphs (c) and (g) and by adding paragraphs (h) through (k) to read as follows:

§ 63.11195 Are any boilers not subject to this subpart?

The types of boilers listed in paragraphs (a) through (k) of this section are not subject to this subpart and to any requirements in this subpart.

* * * * *

(c) A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (e.g., hazardous waste boilers), unless such units do not combust hazardous waste and combust comparable fuels.

* * * * *

(g) Any boiler 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 is provided by regulated gas streams that are subject to another standard.

(h) Temporary boilers as defined in this subpart.

(i) Residential boilers as defined in this subpart.

(j) Electric boilers as defined in this subpart.

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

■ 5. Section 63.11196 is amended by revising paragraphs (a)(1) and (d) to read as follows:

§ 63.11196 What are my compliance dates?

(a) * * *

(1) If the existing affected boiler is subject to a work practice or management practice standard of a tune-up, you must achieve compliance with the work practice or management

practice standard no later than March 21, 2014.

* * * * *

(d) If you own or operate an industrial, commercial, or institutional boiler and would be subject to this subpart except for the exemption in § 63.11195(b) for commercial and industrial solid waste incineration units covered by 40 CFR part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the waste to fuel switch as specified in § 60.2145(a)(2) and (3) of subpart CCCC or § 60.2710(a)(2) and (3) of subpart DDDD.

■ 6. Section 63.11200 is revised to read as follows:

§ 63.11200 What are the subcategories of boilers?

The subcategories of boilers, as defined in § 63.11237 are:

(a) Coal.

(b) Biomass.

(c) Oil.

(d) Seasonal boilers.

(e) Oil-fired boilers with heat input capacity of equal to or less than 5 million British thermal units (Btu) per hour.

(f) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up.

(g) Limited-use boilers.

■ 7. Section 63.11201 is amended by revising paragraphs (b) and (d) to read as follows:

§ 63.11201 What standards must I meet?

* * * * *

(b) You must comply with each work practice standard, emission reduction measure, and management practice specified in Table 2 to this subpart that applies to your boiler. An energy assessment completed on or after January 1, 2008 that meets or is amended to meet the energy assessment requirements in Table 2 to this subpart satisfies the energy assessment requirement. A facility that operates under an energy management program established through energy management systems compatible with ISO 50001, that includes the affected units, also satisfies the energy assessment requirement.

* * * * *

(d) These standards apply at all times the affected boiler is operating, except during periods of startup and shutdown as defined in § 63.11237, during which time you must comply only with Table 2 to this subpart.

■ 8. Section 63.11205 is amended by revising paragraphs (b), (c) introductory

text, (c)(1) introductory text, and (c)(1)(i) to read as follows:

§ 63.11205 What are my general requirements for complying with this subpart?

(b) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or a continuous monitoring system (CMS), including a continuous emission monitoring system (CEMS), a continuous opacity monitoring system (COMS), or a continuous parameter monitoring system (CPMS), where applicable. You may demonstrate compliance with the applicable mercury emission limit using fuel analysis if the emission rate calculated according to § 63.11211(c) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using stack testing.

(c) If you demonstrate compliance with any applicable emission limit through performance stack testing and subsequent compliance with operating limits (including the use of CPMS), with a CEMS, or with a COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (c)(1) through (3) 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 paragraphs (c)(1)(i) through (vi) 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 § 63.11224.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

* * * * *

■ 9. Section 63.11210 is amended by revising paragraphs (b) through (e) and adding paragraphs (f) through (j) to read as follows:

§ 63.11210 What are my initial compliance requirements and by what date must I conduct them?

* * * * *

(b) For existing affected boilers that have applicable emission limits, you must demonstrate initial compliance with the applicable emission limits no later than 180 days after the compliance date that is specified in § 63.11196 and according to the applicable provisions in § 63.7(a)(2), except as provided in paragraph (j) of this section.

(c) For existing affected boilers that have applicable work practice standards, management practices, or emission reduction measures, you must demonstrate initial compliance no later than the compliance date that is specified in § 63.11196 and according to the applicable provisions in § 63.7(a)(2), except as provided in paragraph (j) of this section.

(d) For new or reconstructed affected boilers that have applicable emission limits, you must demonstrate initial compliance with the applicable emission limits no later than 180 days after March 21, 2011 or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(e) For new or reconstructed oil-fired boilers that combust only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM emission limit under this subpart and that do not use a post-combustion technology (except a wet scrubber) to reduce particulate matter (PM) or sulfur dioxide emissions, you are not subject to the PM emission limit in Table 1 of this subpart providing you monitor and record on a monthly basis the type of fuel combusted. If you intend to burn a new type of fuel or fuel mixture that does not meet the requirements of this paragraph, you must conduct a performance test within 60 days of burning the new fuel.

(f) For new or reconstructed affected boilers that have applicable work practice standards or management practices, you are not required to complete an initial performance tune-up, but you are required to complete the applicable biennial or 5-year tune-up as specified in § 63.11223 no later than 25 months or 61 months, respectively, after the initial startup of the new or reconstructed affected source.

(g) For affected boilers that ceased burning solid waste consistent with § 63.11196(d) and for which your initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch as specified in § 60.2145(a)(2) and (3) of subpart CCCC or

§ 60.2710(a)(2) and (3) of subpart DDDD. 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.

(h) For affected boilers that switch fuels or make a physical change to the boiler that results in the applicability of a different subcategory within subpart JJJJJ or the boiler becoming subject to subpart JJJJJ, you must demonstrate compliance within 180 days of the effective date of the fuel switch or the physical change. Notification of such changes must be submitted according to § 63.11225(g).

(i) For boilers located at existing major sources of HAP that limit their potential to emit (e.g., make a physical change or take a permit limit) such that the existing major source becomes an area source, you must comply with the applicable provisions as specified in paragraphs (i)(1) through (3) of this section.

(1) Any such existing boiler at the existing source must demonstrate compliance with subpart JJJJJ within 180 days of the later of March 21, 2014 or upon the existing major source commencing operation as an area source.

(2) Any new or reconstructed boiler at the existing source must demonstrate compliance with subpart JJJJJ within 180 days of the later of March 21, 2011 or startup.

(3) Notification of such changes must be submitted according to § 63.11225(g).

(j) For existing affected boilers that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.11196, you must comply with the applicable provisions as specified in paragraphs (j)(1) through (3) of this section.

(1) You must complete the initial compliance demonstration, if subject to the emission limits in Table 1 to this subpart, as specified in paragraphs (a) and (b) of this section, no later than 180 days after the re-start of the affected boiler and according to the applicable provisions in § 63.7(a)(2).

(2) You must complete the initial performance tune-up, if subject to the tune-up requirements in § 63.11223, by following the procedures described in § 63.11223(b) no later than 30 days after the re-start of the affected boiler.

(3) You must complete the one-time energy assessment, if subject to the energy assessment requirements specified in Table 2 to this subpart, no

later than the compliance date specified in § 63.11196.

■ 10. Section 63.11211 is amended by revising paragraphs (a), (b)(1), and (b)(2) to read as follows:

§ 63.11211 How do I demonstrate initial compliance with the emission limits?

(a) For affected boilers that demonstrate compliance with any of the emission limits of this subpart through performance (stack) testing, your initial compliance requirements include conducting performance tests according to § 63.11212 and Table 4 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler according to § 63.11213 and Table 5 to this subpart, establishing operating limits according to § 63.11222, Table 6 to this subpart and paragraph (b) of this section, as applicable, and conducting CMS performance evaluations according to § 63.11224. For affected boilers that burn a single type of fuel, you are exempted from the compliance requirements of conducting a fuel analysis for each type of fuel burned in your boiler. For purposes of this subpart, boilers that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected boilers that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.11213 and Table 5 to this subpart.

(b) * * *

(1) For a wet scrubber, you must establish the minimum scrubber liquid flow rate and minimum scrubber pressure drop as defined in § 63.11237, as your operating limits during the three-run performance stack test. If you use a wet scrubber and you conduct separate performance stack tests for PM and mercury emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. If you conduct multiple performance stack tests, you must set the minimum scrubber liquid flow rate and pressure drop operating limits at the highest minimum values established during the performance stack tests.

(2) For an electrostatic precipitator operated with a wet scrubber, you must establish the minimum total secondary electric power (secondary voltage and secondary current), as defined in § 63.11237, as your operating limits during the three-run performance stack test.

* * * * *

■ 11. Section 63.11212 is amended by revising paragraphs (b) and (e) to read as follows:

§ 63.11212 What stack tests and procedures must I use for the performance tests?

* * * * *

(b) You must conduct each stack test according to the requirements in Table 4 to this subpart. Boilers that use a CEMS for carbon monoxide (CO) are exempt from the initial CO performance testing in Table 4 to this subpart and the oxygen concentration operating limit requirement specified in Table 3 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 of appendix A-7 to part 60 of this chapter to convert the measured PM concentrations and the measured mercury concentrations that result from the performance test to pounds per million Btu heat input emission rates.

■ 12. Section 63.11214 is amended by revising paragraph (c) to read as follows:

§ 63.11214 How do I demonstrate initial compliance with the work practice standard, emission reduction measures, and management practice?

* * * * *

(c) If you own or operate an existing affected boiler with a heat input capacity of 10 million Btu per hour or greater, you must submit a signed certification in the Notification of Compliance Status report that an energy assessment of the boiler and its energy use systems was completed according to Table 2 to this subpart and is an accurate depiction of your facility.

* * * * *

■ 13. Section 63.11220 is revised to read as follows:

§ 63.11220 When must I conduct subsequent performance tests or fuel analyses?

(a) If your boiler has a heat input capacity of 10 million British thermal units per hour or greater, you must conduct all applicable performance (stack) tests according to § 63.11212 on a triennial basis, except as specified in paragraphs (b) through (d) of this section. Triennial performance tests must be completed no more than 37 months after the previous performance test.

(b) When demonstrating initial compliance with the PM emission limit, if your boiler's performance test results show that your PM emissions are equal to or less than half of the PM emission limit, you do not need to conduct further performance tests for PM but must continue to comply with all applicable operating limits and

monitoring requirements. If your initial performance test results show that your PM emissions are greater than half of the PM emission limit, you must conduct subsequent performance tests as specified in paragraph (a) of this section.

(c) If you demonstrate compliance with the mercury emission limit based on fuel analysis, you must conduct a fuel analysis according to § 63.11213 for each type of fuel burned as specified in paragraphs (c)(1) and (2) of this section. If you plan to burn a new type of fuel or fuel mixture, you must conduct a fuel analysis before burning the new type of fuel or mixture in your boiler. You must recalculate the mercury emission rate using Equation 1 of § 63.11211. The recalculated mercury emission rate must be less than the applicable emission limit.

(1) When demonstrating initial compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are measured to be equal to or less than half of the mercury emission limit, you do not need to conduct further fuel analysis sampling but must continue to comply with all applicable operating limits and monitoring requirements.

(2) When demonstrating initial compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are greater than half of the mercury emission limit, you must conduct quarterly sampling.

(d) For existing affected boilers that have not operated since the previous compliance demonstration and more than 3 years have passed since the previous compliance demonstration, you must complete your subsequent compliance demonstration no later than 180 days after the re-start of the affected boiler.

■ 14. Section 63.11221 is revised to read as follows:

§ 63.11221 Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.11205(c).

(b) You must operate the monitoring system and collect data at all required intervals at all times the affected source 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), repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality 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 collected 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 quality control activities in calculations used to report emissions or operating levels. Any such periods must be reported according to the requirements in § 63.11225. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan), failure to collect required data is a deviation of the monitoring requirements.

■ 15. Section 63.11223 is amended by revising paragraphs (a), (b) introductory text, (b)(1), (b)(3) through (5), (b)(6) introductory text, (b)(6)(i), (b)(6)(iii), (b)(7), and (c), and adding paragraphs (d) through (g) to read as follows:

§ 63.11223 How do I demonstrate continuous compliance with the work practice and management practice standards?

(a) For affected sources subject to the work practice standard or the management practices of a tune-up, you must conduct a performance tune-up according to paragraph (b) of this section and keep records as required in § 63.11225(c) to demonstrate continuous compliance. You must conduct the tune-up while burning the type of fuel (or fuels in the case of boilers that routinely burn two types of fuels at the same time) that provided the majority of

the heat input to the boiler over the 12 months prior to the tune-up.

(b) Except as specified in paragraphs (c) through (f) of this section, you must conduct a tune-up of the boiler biennially to demonstrate continuous compliance as specified in paragraphs (b)(1) through (7) of this section. Each biennial tune-up must be conducted no more than 25 months after the previous tune-up. For a new or reconstructed boiler, the first biennial tune-up must be no later than 25 months after the initial startup of the new or reconstructed boiler.

(1) 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, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection.

* * * * *

(3) 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, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection.

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

(5) 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.

(6) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (b)(6)(i) through (iii) of this section.

(i) 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.

* * * * *

(iii) The type and amount of fuel used over the 12 months prior to the tune-up of the boiler, 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 use by each unit.

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

(c) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up must conduct a tune-up of the boiler every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed boiler with an oxygen trim system, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months.

(d) Seasonal boilers must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed seasonal boiler, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months. Seasonal boilers are not subject to the emission limits in Table 1 to this subpart or the operating limits in Table 3 to this subpart.

(e) Oil-fired boilers with a heat input capacity of equal to or less than 5 million Btu per hour must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed oil-fired boiler with a heat input capacity of equal to or less than 5 million Btu per hour, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified

in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months.

(f) Limited-use boilers must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed limited-use boiler, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months. Limited-use boilers are not subject to the emission limits in Table 1 to this subpart, the energy assessment requirements in Table 2 to this subpart, or the operating limits in Table 3 to this subpart.

(g) If you own or operate a boiler subject to emission limits in Table 1 of this subpart, you must minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if

manufacturer's recommended procedures are not available.

■ 16. Section 63.11224 is amended by:

■ a. Revising paragraphs (a) introductory text, (a)(1) through (3), (a)(5), (a)(6),

■ b. Adding paragraph (a)(7).

■ c. Revising paragraphs (c)(1) introductory text, (c)(2) introductory text, and (d).

■ d. Revising paragraphs (e) introductory text, (e)(6), and (e)(7).

■ e. Adding paragraph (e)(8).

■ f. Revising paragraph (f)(7).

The revisions and additions read as follows:

§ 63.11224 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler is subject to a CO emission limit in Table 1 to this subpart, you must either install, operate, and maintain a CEMS for CO and oxygen according to the procedures in paragraphs (a)(1) through (6) of this section, or install, calibrate, operate, and maintain an oxygen analyzer system, as defined in § 63.11237, according to the manufacturer's recommendations and paragraphs (a)(7) and (d) of this section, as applicable, by the compliance date specified in § 63.11196. Where a certified CO CEMS is used, the CO level shall be monitored at the outlet of the boiler, after any add-on controls or flue gas recirculation system and before release to the atmosphere. Boilers that use a CO CEMS are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in § 63.11211(a) of this subpart. Oxygen monitors and oxygen trim systems must be installed to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location.

(1) Each CO CEMS must be installed, operated, and maintained according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, and each oxygen CEMS must be installed, operated, and maintained according to Performance Specification 3 at 40 CFR part 60, appendix B. Both the CO and oxygen CEMS must also be installed, operated, and maintained according to the site-specific monitoring plan developed according to paragraph (c) of this section.

(2) You must conduct a performance evaluation of each CEMS according to the requirements in § 63.8(e) and according to Performance Specifications 3 and 4, 4A, or 4B at 40 CFR part 60, appendix B.

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) every 15 minutes. You must have CEMS data values from a minimum of four successive cycles of operation representing each of 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, to have a valid hour of data.

* * * * *

(5) You must calculate hourly averages, corrected to 3 percent oxygen, from each hour of CO CEMS data in parts per million CO concentrations and determine the 10-day rolling average of all recorded readings, except as provided in § 63.11221(c). Calculate a 10-day rolling average from all of the hourly averages collected for the 10-day operating period using Equation 2 of this section.

$$\text{10-day average} = \frac{\sum_{i=1}^n Hpvi}{n} \quad (\text{Eq. 2})$$

Where:

Hpvi = the hourly parameter value for hour i

n = the number of valid hourly parameter values collected over 10 boiler operating days

(6) For purposes of collecting CO data, you must operate the CO CEMS as specified in § 63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in § 63.11221(c). Periods when CO data are unavailable may constitute

monitoring deviations as specified in § 63.11221(d).

(7) You must operate the oxygen analyzer system at or above the minimum oxygen level that is established as the operating limit according to Table 6 to this subpart when firing the fuel or fuel mixture utilized during the most recent CO performance stack test. Operation of oxygen trim systems to meet these requirements shall not be done in a manner which compromises furnace safety.

* * * * *

(c) * * *

(1) For each CMS required in this section, you must develop, and submit to the EPA Administrator for approval upon request, a site-specific monitoring plan that addresses paragraphs (c)(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.

* * * * *

(2) In your site-specific monitoring plan, you must also address paragraphs (c)(2)(i) through (iii) of this section.

* * * * *

(d) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each CPMS according to the procedures in paragraphs (d)(1) through (4) of this section.

(1) The CPMS must complete a minimum of one cycle of operation every 15 minutes. You must have data values from a minimum of four successive cycles of operation representing each of 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, to have a valid hour of data.

(2) You must calculate hourly arithmetic averages from each hour of CPMS data in units of the operating limit and determine the 30-day rolling average of all recorded readings, except as provided in § 63.11221(c). Calculate a 30-day rolling average from all of the hourly averages collected for the 30-day operating period using Equation 3 of this section.

$$\text{30-day average} = \frac{\sum_{i=1}^n Hpvi}{n} \quad (\text{Eq. 3})$$

Where:

Hpvi = the hourly parameter value for hour i

n = the number of valid hourly parameter values collected over 30 boiler operating days

(3) For purposes of collecting data, you must operate the CPMS as specified in § 63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in § 63.11221(c). Periods when CPMS data are unavailable may constitute monitoring deviations as specified in § 63.11221(d).

(4) Record the results of each inspection, calibration, and validation check.

(e) If you have an applicable opacity operating limit under this rule, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (e)(1) through (8) of this section by the compliance date specified in § 63.11196.

* * * * *

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit.

(7) You must calculate and record 6-minute averages from the opacity monitoring data and determine and record the daily block average of recorded readings, except as provided in § 63.11221(c).

(8) For purposes of collecting opacity data, you must operate the COMS as specified in § 63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except

that you must exclude certain data as specified in § 63.11221(c). Periods when COMS data are unavailable may constitute monitoring deviations as specified in § 63.11221(d).

(f) * * *

(7) For positive pressure fabric filter systems that do not duct all compartments or cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

* * * * *

■ 17. Section 63.11225 is amended by:

■ a. Revising paragraphs (a) introductory text, (a)(1), (a)(2), (a)(4), (a)(5), (b) introductory text, (b)(2), (c) introductory text, (c)(2) introductory text, and (c)(2)(ii).

■ b. Adding paragraphs (c)(2)(iii) through (vi).

■ c. Revising paragraphs (d), (e), and (g).

The revisions and additions read as follows:

§ 63.11225 What are my notification, reporting, and recordkeeping, requirements?

(a) You must submit the notifications specified in paragraphs (a)(1) through (5) of this section to the administrator.

(1) You must submit all of the notifications in §§ 63.7(b); 63.8(e) and (f); and 63.9(b) through (e), (g), and (h) that apply to you by the dates specified in those sections except as specified in paragraphs (a)(2) and (4) of this section.

(2) An Initial Notification must be submitted no later than January 20, 2014 or within 120 days after the source becomes subject to the standard.

* * * * *

(4) You must submit the Notification of Compliance Status no later than 120 days after the applicable compliance date specified in § 63.11196 unless you must conduct a performance stack test. If you must conduct a performance stack test, you must submit the Notification of Compliance Status within 60 days of

completing the performance stack test. You must submit the Notification of Compliance Status in accordance with paragraphs (a)(4)(i) and (vi) of this section. The Notification of Compliance Status must include the information and certification(s) of compliance in paragraphs (a)(4)(i) through (v) of this section, as applicable, and signed by a responsible official.

(i) You must submit the information required in § 63.9(h)(2), except the information listed in § 63.9(h)(2)(i)(B), (D), (E), and (F). If you conduct any performance tests or CMS performance evaluations, you must submit that data as specified in paragraph (e) of this section. If you conduct any opacity or visible emission observations, or other monitoring procedures or methods, you must submit that data to the Administrator at the appropriate address listed in § 63.13.

(ii) “This facility complies with the requirements in § 63.11214 to conduct an initial tune-up of the boiler.”

(iii) “This facility has had an energy assessment performed according to § 63.11214(c).”

(iv) For units that install bag leak detection systems: “This facility complies with the requirements in § 63.11224(f).”

(v) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: “No secondary materials that are solid waste were combusted in any affected unit.”

(vi) The notification must be submitted electronically using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through 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 written Notification of Compliance Status must be submitted to the

Administrator at the appropriate address listed in § 63.13.

(5) If you are using data from a previously conducted emission test to serve as documentation of conformance with the emission standards and operating limits of this subpart, you must include in the Notification of Compliance Status the date of the test and a summary of the results, not a complete test report, relative to this subpart.

(b) You must prepare, by March 1 of each year, and submit to the delegated authority upon request, an annual compliance certification report for the previous calendar year containing the information specified in paragraphs (b)(1) through (4) of this section. You must submit the report by March 15 if you had any instance described by paragraph (b)(3) of this section. For boilers that are subject only to a requirement to conduct a biennial or 5-year tune-up according to § 63.11223(a) and not subject to emission limits or operating limits, you may prepare only a biennial or 5-year compliance report as specified in paragraphs (b)(1) and (2) of this section.

* * * * *

(2) Statement by a responsible official, with the official's name, title, phone number, email address, and signature, certifying the truth, accuracy and completeness of the notification and a statement of whether the source has complied with all the relevant standards and other requirements of this subpart. Your notification must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility complies with the requirements in § 63.11223 to conduct a biennial or 5-year tune-up, as applicable, of each boiler."

(ii) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: "No secondary materials that are solid waste were combusted in any affected unit."

(iii) "This facility complies with the requirement in §§ 63.11214(d) and 63.11223(g) to minimize the boiler's time spent during startup and shutdown and to conduct startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available."

* * * * *

(c) You must maintain the records specified in paragraphs (c)(1) through (7) of this section.

* * * * *

(2) You must keep records to document conformance with the work practices, emission reduction measures, and management practices required by § 63.11214 and § 63.11223 as specified in paragraphs (c)(2)(i) through (vi) of this section.

* * * * *

(ii) For operating units that combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) of this chapter, you must keep a record which documents how the secondary material meets each of the legitimacy criteria under § 241.3(d)(1). 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 satisfies the definition of processing in § 241.2 and each of the legitimacy criteria in § 241.3(d)(1) 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, you must keep records documenting that the material is a listed non-waste under § 241.4(a).

(iii) For each boiler required to conduct an energy assessment, you must keep a copy of the energy assessment report.

(iv) For each boiler subject to an emission limit in Table 1 to this subpart, you must also keep records of monthly fuel use by each boiler, including the type(s) of fuel and amount(s) used.

(v) For each boiler that meets the definition of seasonal boiler, you must keep records of days of operation per year.

(vi) For each boiler that meets the definition of limited-use boiler, 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 records of fuel use for the days the boiler is operating.

* * * * *

(d) Your records must be in a form suitable and readily available for expeditious review. You must keep each record for 5 years following the date of each recorded action. You must keep each record on-site or be accessible from a central location by computer or other means that instantly provide access at the site for at least 2 years after the date of each recorded action. You may keep the records off site for the remaining 3 years.

(e)(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 to EPA's WebFIRE database by using CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of 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 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 EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including CBI, to the delegated authority in the format specified by the delegated authority. 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 at the appropriate address listed in § 63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation test as defined in § 63.2, you must submit relative accuracy test audit (RATA) data to EPA's CDX by using CEDRI in accordance with paragraph (e)(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 at the appropriate address listed in § 63.13.

* * * * *

(g) If you have switched fuels or made a physical change to the boiler and the fuel switch or change resulted in the

applicability of a different subcategory within subpart JJJJJJ, in the boiler becoming subject to subpart JJJJJJ, or in the boiler switching out of subpart JJJJJJ due to a change to 100 percent natural gas, or you have taken a permit limit that resulted in you being subject to subpart JJJJJJ, you must provide notice of the date upon which you switched fuels, made the physical change, or took a permit limit within 30 days of the change. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that have switched fuels, were physically changed, or took a permit limit, and the date of the notice.

(2) The date upon which the fuel switch, physical change, or permit limit occurred.

18. Section 63.11226 is revised to read as follows:

§ 63.11226 Affirmative defense for violation of emission standards during malfunction.

In response to an action to enforce the standards set forth in § 63.11201 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 40 CFR 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 paragraph (a) 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.

■ 19. Section 63.11236 is amended by revising paragraph (a) to read as follows:

§ 63.11236 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by 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 has the authority to implement and enforce this subpart.

You should contact your EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to your state, local, or tribal agency.

* * * * *

■ 20. Section 63.11237 is amended as follows:

■ a. By adding definitions in alphabetical order for “10-day rolling average,” “30-day rolling average,” “Annual heat input,” “Biodiesel,” “Calendar year,” “Common stack,” “Daily block average,” “Distillate oil,” “Electric boiler,” “Electric utility steam generating unit (EGU),” “Energy management program,” “Fluidized bed boiler,” “Fluidized bed combustion,” “Hourly average,” “Limited-use boiler,” “Load fraction,” “Minimum scrubber pressure drop,” “Minimum sorbent injection rate,” “Minimum total secondary electric power,” “Operating day,” “Oxygen analyzer system,” “Oxygen trim system,” “Process heater,” “Regulated gas stream,” “Residential boiler,” “Residual oil,” “Seasonal boiler,” “Shutdown,” “Solid fuel,” “Startup,” “Temporary boiler,” “Tune-up,” “Vegetable oil,” “Voluntary Consensus Standards (VCS),” and “Wet scrubber.”

■ b. By revising the definitions for “Bag leak detection system,” “Biomass subcategory,” “Boiler,” “Boiler system,” “Deviation,” “Dry scrubber,” “Electrostatic precipitator (ESP),” “Energy assessment,” “Energy use system,” “Federally enforceable,” “Gas-fired boiler,” “Heat input,” “Hot water heater,” “Institutional boiler,” “Liquid fuel,” “Minimum activated carbon injection rate,” “Minimum oxygen level,” “Minimum scrubber liquid flow rate,” “Natural gas,” “Oil subcategory,” “Particulate matter,” “Period of gas curtailment or supply interruption,” “Qualified Energy Assessor,” “Solid fossil fuel,” and “Waste heat boiler.”

■ c. By removing the definitions for “Annual heat input basis,” “Minimum PM scrubber pressure drop,” “Minimum sorbent flow rate,” and “Minimum voltage or amperage”.

§ 63.11237 What definitions apply to this subpart?

10-day rolling average means the arithmetic mean of all valid hours of data from 10 successive operating days, except for periods of startup and shutdown and periods when the unit is not operating.

30-day rolling average means the arithmetic mean of all valid hours of data from 30 successive operating days, except for periods of startup and shutdown and periods when the unit is not operating.

* * * * *

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Bag leak detection system means a group of instruments that are capable of monitoring particulate matter loadings in the exhaust of a fabric filter (*i.e.*, baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

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).

* * * * *

Biomass subcategory includes any boiler that burns any biomass and is not in the coal subcategory.

Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/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, process heaters, and autoclaves are excluded from the definition of *Boiler*.

Boiler system means the boiler and associated components, such as, feedwater systems, combustion air systems, fuel systems (including burners), blowdown systems, combustion control systems, steam systems, and condensate return systems, directly connected to and serving the energy use systems.

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

* * * * *

Common stack means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

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 and periods when the unit is not operating.

Deviation (1) 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 § 63.14).

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.

Electric boiler means a boiler in which electric heating serves as the source of heat. Electric boilers that burn gaseous or liquid fuel during periods of electrical power curtailment or failure are included in this definition.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts 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 megawatts electrical 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, 2015.

Electrostatic precipitator (ESP) means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.

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

(1) The energy assessment for facilities with affected boilers with less than 0.3 trillion Btu per year (TBtu/year) heat input capacity 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, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour energy assessment.

(2) The energy assessment for facilities with affected boilers with 0.3 to 1.0 TBtu/year heat input capacity 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 affected boiler(s) energy (*e.g.*, steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour energy assessment.

(3) The energy assessment for facilities with affected boilers with greater than 1.0 TBtu/year heat input capacity will be up to 24 on-site technical labor hours in length for the first TBtu/year plus 8 on-site technical labor hours for every additional 1.0 TBtu/year 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) and any on-site energy use system(s) accounting for at least 20 percent of the affected boiler(s) energy (e.g., steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use system(s) serving as the basis for the percent of affected boiler(s) energy production, as applicable, 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 (1) Includes the following systems located on the site of the affected boiler that use energy provided by the boiler:

(i) 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

(ii) Other systems that use steam, hot water, process heat, or electricity, provided by the affected boiler.

(2) Energy use systems are only those systems using energy clearly produced by affected boilers.

* * * * *

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 combustion means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by

the forward flow of air and combustion products.

* * * * *

Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

Heat input means heat derived from combustion of fuel in a boiler 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.

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 fuel and hot water 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 million Btu per hour heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on-demand hot water.

Hourly average means the arithmetic average of 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.

* * * * *

Institutional boiler means a boiler used in institutional establishments such as, but not limited to, medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, and governmental buildings to provide electricity, steam, and/or hot water.

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

Liquid fuel includes, but is not limited to, distillate oil, residual oil, any form of liquid fuel derived from petroleum, used oil meeting the specification in 40 CFR 279.11, liquid biofuels, biodiesel, and vegetable oil,

and comparable fuels as defined under 40 CFR 261.38.

Load fraction means the actual heat input of a boiler 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).

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable carbon monoxide emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average scrubber liquid flow rate (e.g., to the particulate matter scrubber) measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 6 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 6 to this subpart during the most recent performance stack 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.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits.

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 by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions (*i.e.*, a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals). 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 C₃H₈.

Oil subcategory includes any boiler that burns any liquid fuel and is not in either the biomass or coal subcategories. Gas-fired boilers that burn liquid fuel only during periods of gas curtailment, gas supply interruptions, startups, or for periodic testing are not included in this definition. Periodic testing on liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

* * * * *

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location. This definition includes oxygen trim systems.

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 carbon monoxide monitor that automatically provides a feedback signal to the combustion air controller.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

* * * * *

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler 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.

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. Process heaters include units that heat water/water mixtures for pool heating, sidewalk heating, cooling tower water heating, power washing, or oil heating.

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.

(vii) 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 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)).

* * * * *

Seasonal boiler means a boiler that undergoes a shutdown for a period of at least 7 consecutive months (or 210 consecutive days) each 12-month period due to seasonal conditions, except for periodic testing. Periodic testing shall not exceed a combined total of 15 days during the 7-month shutdown. This definition only applies to boilers that would otherwise be included in the biomass subcategory or the oil subcategory.

Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam or heat 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, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler.

Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire-derived fuel.

Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel.

Startup means either the first-ever firing of fuel in a boiler 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 is supplied for heating and/or producing electricity, or for any other purpose.

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 within the facility and performs the same or similar function will be included in calculating the consecutive time period unless there is a gap in operation of 12 months or more.

(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.

Tune-up means adjustments made to a boiler in accordance with the procedures outlined in § 63.11223(b).

Vegetable oil means oils extracted from vegetation.

Voluntary Consensus Standards (VCS) mean technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies.

EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English.

Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, <http://www.astm.org>), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, <http://www.asme.org>), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, +41 22 749 01 11, <http://www.iso.org/iso/home.htm>), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 <http://www.stadards.org.au>), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, +44 (0)20 8996 9001, <http://www.bsigroup.com>), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800–463–6727, <http://www.csa.ca>), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B–1000 Brussels, Belgium +32 2 550 08 11, <http://www.cen.eu/cen>), and German Engineering Standards (VDI VDI Guidelines

Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, +49 211 6214–230, <http://www.vdi.eu>). The types of standards that are not considered VCS are standards developed by: the United States, e.g., California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, e.g., Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

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.

Wet scrubber means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

* * * * *

■ 21. Table 1 to subpart JJJJJJ is revised to read as follows:

As stated in § 63.11201, you must comply with the following applicable emission limits:

TABLE 1 TO SUBPART JJJJJJ OF PART 63—EMISSION LIMITS

If your boiler is in this subcategory . . .	For the following pollutants . . .	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown . . .
1. New coal-fired boilers with heat input capacity of 30 million British thermal units per hour (MMBtu/hr) or greater that do not meet the definition of limited-use boiler.	a. PM (Filterable) b. Mercury c. CO	3.0E–02 pounds(lb) per million British thermal units (MMBtu) of heat input. 2.2E–05 lb per MMBtu of heat input. 420 parts per million (ppm) by volume on a dry basis corrected to 3 percent oxygen (3-run average or 10-day rolling average).
2. New coal-fired boilers with heat input capacity of between 10 and 30 MMBtu/hr that do not meet the definition of limited-use boiler.	a. PM (Filterable) b. Mercury c. CO	4.2E–01 lb per MMBtu of heat input. 2.2E–05 lb per MMBtu of heat input. 420 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average or 10-day rolling average).

TABLE 1 TO SUBPART JJJJJJ OF PART 63—EMISSION LIMITS—Continued

If your boiler is in this subcategory . . .	For the following pollutants . . .	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown . . .
3. New biomass-fired boilers with heat input capacity of 30 MMBtu/hr or greater that do not meet the definition of seasonal boiler or limited-use boiler.	PM (Filterable)	3.0E–02 lb per MMBtu of heat input.
4. New biomass fired boilers with heat input capacity of between 10 and 30 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler.	PM (Filterable)	7.0E–02 lb per MMBtu of heat input.
5. New oil-fired boilers with heat input capacity of 10 MMBtu/hr or greater that do not meet the definition of seasonal boiler or limited-use boiler.	PM (Filterable)	3.0E–02 lb per MMBtu of heat input.
6. Existing coal-fired boilers with heat input capacity of 10 MMBtu/hr or greater that do not meet the definition of limited-use boiler.	a. Mercury b. CO	2.2E–05 lb per MMBtu of heat input. 420 ppm by volume on a dry basis corrected to 3 percent oxygen.

■ 22. Table 2 to subpart JJJJJJ is revised to read as follows:

As stated in § 63.11201, you must comply with the following applicable work practice standards, emission

reduction measures, and management practices:

TABLE 2 TO SUBPART JJJJJJ OF PART 63—WORK PRACTICE STANDARDS, EMISSION REDUCTION MEASURES, AND MANAGEMENT PRACTICES

If your boiler is in this subcategory . . .	You must meet the following . . .
1. Existing or new coal-fired, new biomass-fired, or new oil-fired boilers (units with heat input capacity of 10 MMBtu/hr or greater).	Minimize the boiler's startup and shutdown periods and conduct startups and shutdowns according to the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available.
2. Existing coal-fired boilers with heat input capacity of less than 10 MMBtu/hr that do not meet the definition of limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.
3. New coal-fired boilers with heat input capacity of less than 10 MMBtu/hr that do not meet the definition of limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
4. Existing oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.
5. New oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
6. Existing biomass-fired boilers that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.
7. New biomass-fired boilers that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
8. Existing seasonal boilers	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
9. New seasonal boilers	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
10. Existing limited-use boilers	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
11. New limited-use boilers	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
12. Existing oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr.	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
13. New oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr.	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.

TABLE 2 TO SUBPART JJJJJ OF PART 63—WORK PRACTICE STANDARDS, EMISSION REDUCTION MEASURES, AND MANAGEMENT PRACTICES—Continued

If your boiler is in this subcategory . . .	You must meet the following . . .
14. Existing coal-fired, biomass-fired, or oil-fired boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up.	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
15. New coal-fired, biomass-fired, or oil-fired boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up.	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
16. Existing coal-fired, biomass-fired, or oil-fired boilers (units with heat input capacity of 10 MMBtu/hr and greater), not including limited-use boilers.	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. Energy assessor approval and qualification requirements are waived in instances where past or amended energy assessments are used to meet the energy assessment requirements. 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 (1) to (4) appropriate for the on-site technical hours listed in § 63.11237: (1) A visual inspection of the boiler system, (2) An evaluation of operating characteristics of the affected boiler systems, specifications of energy use systems, operating and maintenance procedures, and unusual operating constraints, (3) An inventory of major energy use systems consuming energy from affected boiler(s) and which are under control of the boiler owner or operator, (4) A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage, (5) A list of major energy conservation measures that are within the facility's control, (6) A list of the energy savings potential of the energy conservation measures identified, and (7) A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

■ 23. Table 3 to subpart JJJJJ is revised to read as follows:

As stated in § 63.11201, you must comply with the applicable operating limits:

TABLE 3 TO SUBPART JJJJJ OF PART 63—OPERATING LIMITS FOR BOILERS WITH EMISSION LIMITS

If you demonstrate compliance with applicable emission limits using . . .	You must meet these operating limits except during periods of startup and shutdown . . .
1. Fabric filter control	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 § 63.11224 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period.
2. Electrostatic precipitator control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR b. Maintain the 30-day rolling average total secondary electric power of the electrostatic precipitator at or above the minimum total secondary electric power as defined in § 63.11237.
3. Wet scrubber control	Maintain the 30-day rolling average pressure drop across the wet scrubber at or above the minimum scrubber pressure drop as defined in § 63.11237 and the 30-day rolling average liquid flow rate at or above the minimum scrubber liquid flow rate as defined in § 63.11237.
4. Dry sorbent or activated carbon injection control.	Maintain the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent injection rate or minimum activated carbon injection rate as defined in § 63.11237. When your boiler operates at lower loads, multiply your sorbent or activated carbon injection rate by the load fraction (e.g., actual heat input divided by the heat input during the performance stack test; for 50 percent load, multiply the injection rate operating limit by 0.5).
5. Any other add-on air pollution control type. ...	This option is for boilers that operate dry control systems. Boilers must maintain opacity to less than or equal to 10 percent opacity (daily block average).
6. Fuel analysis	Maintain the fuel type or fuel mixture (annual average) such that the mercury emission rate calculated according to § 63.11211(c) are less than the applicable emission limit for mercury.
7. Performance stack testing	For boilers that demonstrate compliance with a performance stack test, maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance stack test.
8. Oxygen analyzer system	For boilers subject to a CO emission limit that demonstrate compliance with an oxygen analyzer system as specified in § 63.11224(a), maintain the 30-day rolling average oxygen level at or above the minimum oxygen level as defined in § 63.11237. 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 § 63.11224(a)(7).

* * * * *

■ 24. Table 6 to subpart JJJJJJ is revised to read as follows:

As stated in § 63.11211, you must comply with the following requirements for establishing operating limits:

TABLE 6 TO SUBPART JJJJJJ 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 or mercury ..	a. Wet scrubber operating parameters.	Establish site-specific minimum scrubber pressure drop and minimum scrubber liquid flow rate operating limits according to § 63.11211(b).	Data from the pressure drop and liquid flow rate monitors and the PM or mercury performance stack tests.	(a) You must collect pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average pressure drop and liquid flow rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
	b. Electrostatic precipitator operating parameters.	Establish a site-specific minimum total secondary electric power operating limit according to § 63.11211(b).	Data from the secondary electric power monitors and the PM or mercury performance stack tests.	(a) You must collect secondary electric power data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average total secondary electric power for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
2. Mercury	Dry sorbent or activated carbon injection rate operating parameters.	Establish a site-specific minimum sorbent or activated carbon injection rate operating limit according to § 63.11211(b).	Data from the sorbent or activated carbon injection rate monitors and the mercury performance stack tests.	(a) You must collect sorbent or activated carbon injection rate data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average sorbent or activated carbon injection rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run. (c) When your unit operates at lower loads, multiply your sorbent or activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance stack test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
3. CO	Oxygen	Establish a unit-specific limit for minimum oxygen level.	Data from the oxygen analyzer system specified in § 63.11224(a).	(a) You must collect oxygen data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average hourly oxygen concentration for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
4. Any pollutant for which compliance is demonstrated by a performance stack test.	Boiler operating load.	Establish a unit-specific limit for maximum operating load according to § 63.11212(c).	Data from the operating load monitors (fuel feed monitors or steam generation monitors).	(a) You must collect operating load data (fuel feed rate or steam generation data) every 15 minutes during the entire period of the performance test. (b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

■ 25. Table 7 to subpart JJJJJJ is revised to read as follows:

As stated in § 63.11222, you must show continuous compliance with the

emission limitations for each boiler according to the following:

TABLE 7 TO SUBPART JJJJJJ OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

If you must meet the following operating limits . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.11224(e) and § 63.11221; 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. Fabric Filter Bag Leak Detection Operation ...	Installing and operating a bag leak detection system according to § 63.11224(f) and operating the fabric filter such that the requirements in § 63.11222(a)(4) are met.
3. Wet Scrubber Pressure Drop and Liquid Flow Rate.	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.11224 and 63.11221; 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 minimum pressure drop and minimum liquid flow rate according to § 63.11211.
4. Dry Scrubber Sorbent or Activated Carbon Injection Rate.	a. Collecting the sorbent or activated carbon injection rate monitoring system data for the dry scrubber according to §§ 63.11224 and 63.11221; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent or activated carbon injection rate according to § 63.11211.
5. Electrostatic Precipitator Total Secondary Electric Power.	a. Collecting the total secondary electric power monitoring system data for the electrostatic precipitator according to §§ 63.11224 and 63.11221; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average total secondary electric power at or above the minimum total secondary electric power according to § 63.11211.
6. Fuel Pollutant Content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.11213 as applicable; and b. Keeping monthly records of fuel use according to §§ 63.11222(a)(2) and 63.11225(b)(4).
7. Oxygen content	a. Continuously monitoring the oxygen content of flue gas according to § 63.11224 (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 § 63.11224(a)(7)); and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average oxygen content at or above the minimum oxygen level established during the most recent CO performance test.
8. CO emissions	a. Continuously monitoring the CO concentration in the combustion exhaust according to §§ 63.11224 and 63.11221; and b. Correcting the data to 3 percent oxygen, and reducing the data to 1-hour averages; and c. Reducing the data from the hourly averages to 10-day rolling averages; and d. Maintaining the 10-day rolling average CO concentration at or below the applicable emission limit in Table 1 to this subpart.
9. Boiler operating load	a. Collecting operating load data (fuel feed rate or steam generation data) every 15 minutes; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average at or below the operating limit established during the performance test according to § 63.11212(c) and Table 6 to this subpart.

■ 26. Table 8 to subpart JJJJJJ is amended by:

■ a. Revising the entry for “§ 63.9”.

■ b. Revising the entry for “§ 63.10(e) and (f)”.

■ c. Adding an entry for “§ 63.10(f)”.

The revisions read as follows:

* * * * *

TABLE 8 TO SUBPART JJJJJJ OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART JJJJJJ

General provisions cite	Subject	Does it apply?
* * *	* * *	* * *
§ 63.9	Notification Requirements	Yes, excluding the information required in § 63.9(h)(2)(i)(B), (D), (E) and (F). See § 63.11225.
* * *	* * *	* * *
§ 63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
* * *	* * *	* * *