ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2006–0790; FRL–9148–3]

RIN 2060–AM44

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing national emission standards for control of hazardous air pollutants from two area source categories: Industrial boilers and commercial and institutional boilers. The proposed emission standards for control of mercury emissions from coal-fired area source boilers and the proposed emission standards for control of polycyclic organic matter emissions from all area source boilers are based on the maximum achievable control technology. The proposed emission standards for control of mercury emissions from biomass-fired and oil-fired area source boilers and for other hazardous air pollutants are based on EPA's proposed determination as to what constitutes the generally available control technology or management practices.

EPA is also clarifying that gas-fired area source boilers are not needed to meet the 90 percent requirement of section 112(c)(3) of the Clean Air Act.

Finally, we are also proposing that existing area source facilities with an affected boiler with a designed heat input capacity of 10 million Btu per hour or greater undergo an energy assessment on the boiler system to identify cost-effective energy conservation measures.

DATES: Comments must be received on or before July 19, 2010. Under the Paperwork Reduction Act, comments on the information collection provisions are best assured of having full effect if the Office of Management and Budget (OMB) receives a copy of your comments on or before July 6, 2010.

Public Hearing. We will hold a public hearing concerning this proposed rule and the interrelated proposed Boiler major source, CISWI, and RCRA rules, discussed in this proposal and published in the proposed rules section of today's **Federal Register**, on June 21, 2010. Persons requesting to speak at a public hearing must contact EPA by June 14, 2010.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2006–0790, by one of the following methods:

- *http://www.regulations.gov.* Follow the instructions for submitting comments.
- *http://www.epa.gov/oar/docket.html.* Follow the instructions for submitting comments on the EPA Air and Radiation Docket Web site.
- *E-mail:* Comments may be sent by electronic mail (e-mail) to *a-and-r-docket@epa.gov,* Attention Docket ID No. EPA–HQ–OAR–2006–0790.
- *Fax:* Fax your comments to: (202) 566–9744, Docket ID No. EPA–HQ–OAR–2006–0790.
- *Mail:* Send your comments to: EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460, Docket ID No. EPA–HQ–OAR–2006–0790. Please include a total of two copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, OMB, Attn: Desk Officer for EPA, 725 17th St., NW., Washington, DC 20503.
- *Hand Delivery or Courier:* Deliver your comments to: EPA Docket Center (EPA/DC), EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC 20460. Attention Docket ID No. EPA–HQ–OAR–2006–0790. Such deliveries are only accepted during the Docket's normal hours of operation (8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holiday), and special arrangements should be made for deliveries of boxed information.

Instructions: All submissions must include agency name and docket number or Regulatory Information Number (RIN) for this rulemaking. All comments will be posted without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov,* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Public Hearing: We will hold a public hearing concerning this proposed rule on June 21, 2010. Persons interested in presenting oral testimony at the hearing should contact Ms. Pamela Garrett, Energy Strategies Group, at (919) 541–7966 by June 14, 2010. The public hearing will be held in the Washington, DC area at a location and time that will be posted at the following Web site: *http://www.epa.gov/airquality/combustion.* Please refer to this Web site to confirm the date of the public hearing as well. If no one requests to speak at the public hearing by June 14, 2010 then the public hearing will be cancelled and a notification of cancellation posted on the following Web site: *http://www.epa.gov/airquality/combustion.*

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA Docket Center, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Mary Johnson, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5025; Fax number (919) 541–5450; e-mail address: *johnson.mary@epa.gov.*

SUPPLEMENTARY INFORMATION:

Outline. The information in this preamble is organized as follows:

I. General Information

A. Does this action apply to me?

The regulated categories and entities potentially affected by the proposed standards include:

Category	NAICS Code [1]	Examples of regulated entities
Any area source facility using a boiler as defined in this proposed rule.	321	Wood product manufacturing.
	11	Agriculture, greenhouses.
	311	Food manufacturing.
	327	Nonmetallic mineral product manufacturing.
	422	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.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. To determine whether your facility, company, business, organization, etc., would be regulated by this action, you should examine the applicability criteria in 40 CFR 63.11193 of subpart JJJJJJ (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 action to a particular entity, consult either the delegated regulatory authority for the entity or your EPA regional representative as listed in 40 CFR 63.13 of subpart A (General Provisions).

B. What should I consider as I prepare my comments to EPA?

Do not submit information containing CBI to EPA through *http://www.regulations.gov* or e-mail. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention: Docket ID EPA–HQ–OAR–2006–0790. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

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

In addition to being available in the docket, an electronic copy of this proposed action will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of the proposed 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.

D. When would a public hearing occur?

We will hold a public hearing concerning this proposed rule on June 21, 2010. Persons interested in presenting oral testimony at the hearing should contact Ms. Pamela Garrett, Energy Strategies Group, at (919) 541–7966 by June 14, 2010. The public hearing will be held in the Washington, DC area at a location and time that will be posted at the following Web site: *http://www.epa.gov/airquality/combustion.* Please refer to this Web site to confirm the date of the public hearing as well. If no one requests to speak at the public hearing by June 14, 2010 then the public hearing will be cancelled and a notification of cancellation posted on the following Web site: *http://www.epa.gov/airquality/combustion.*

II. Background Information

A. What is the statutory authority and regulatory approach for this proposed rule?

Section 112(d) of the Clean Air Act (CAA) requires us to establish NESHAP for both major and area sources of hazardous air pollutants (HAP) that are listed for regulation under CAA section 112(c). A major source emits or has the potential to emit 10 tons per year (tpy) or more of any single HAP or 25 tpy or more of any combination of HAP. An area source is a HAP-emitting stationary source that is not a major source.

CAA section 112(k)(3)(B) calls for EPA to identify at least 30 HAP which, as the result of emissions from area sources, pose the greatest threat to public health in the largest number of urban areas. EPA implemented this provision in 1999 in the Integrated Urban Air Toxics Strategy (Strategy), (64 FR 38715, July 19, 1999). Specifically, in the Strategy, 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." CAA section 112(c)(3) requires 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. A primary goal of the Strategy is to achieve a 75 percent reduction in cancer incidence attributable to HAP emitted from stationary sources.

Under CAA section 112(d)(5), we may elect to promulgate standards or requirements for area sources "which provide for the use of generally available control technologies or management practices ('GACT') by such sources to reduce emissions of hazardous air pollutants." Additional information on GACT is found in the Senate report on the legislation (Senate Report Number 101–228, December 20, 1989), which describes GACT as:

> * * * methods, practices and techniques which are commercially available and appropriate for application by the sources in the category considering economic impacts and the technical capabilities of the firms to operate and maintain the emissions control systems.

Consistent with the legislative history, we can consider costs and economic impacts in determining GACT, which is particularly important when developing regulations for source categories that may have many small businesses such as these.

Determining what constitutes GACT involves considering the control technologies and management practices that are generally available to the area sources in the source category. We also consider the standards applicable to major sources in the analogous source category to determine if the control technologies and management practices are transferable and generally available to area sources. In appropriate circumstances, we may also consider technologies and practices at area and major sources in similar categories to determine whether such technologies and practices could be considered generally available for the area source categories at issue. Finally, as noted above, in determining GACT for a particular area source category, we consider the costs and economic impacts of available control technologies and management practices on that category.

While GACT may be a basis for standards for most types of HAP emitted from area sources, CAA section 112(c)(6) requires that EPA list categories and subcategories of sources assuring that sources accounting for not less than 90 percent of the aggregate emissions of each of the seven specified hazardous air pollutants (HAP) are subject to standards under section 112(d)(2) or (d)(4). The seven HAP specified in section 112(c)(6) are as follows: alkylated lead compounds, polycyclic organic matter, hexachlorobenzene, mercury, polychlorinated biphenyls, 2,3,7,9-tetrachlorodibenzofurans, and 2,3,7,8-tetrachloridibenzo-p-dioxin.

The CAA section 112(c)(6) list of source categories currently includes industrial coal combustion, industrial oil combustion, industrial wood combustion, commercial coal combustion, commercial oil combustion, and commercial wood combustion. See 63 FR 17849. We listed these source categories under CAA section 112(c)(6) based on the source categories' contribution of mercury and polycyclic organic matter (POM). In the documentation for the CAA section 112(c)(6) listing, the commercial fuel combustion categories included institutional fuel combustion (see "1990 Emissions Inventory of Section 112(c)(6) Pollutants, Final Report," April 1998). As discussed in greater detail below, we re-examine the emission inventory and the need to address categories under CAA section 112(c)(6) during the rule development process. Based on this re-examination, we now believe we will only need to address the coal-fueled portion of these categories under CAA section 112(c)(6).

With this proposed rule and the major source boilers rule, we currently believe that we have subjected to regulation or proposed to regulate at least 90 percent of the 1990 section 112(c)(6) emissions inventory for mercury. Coal-fired area source boilers represent approximately 4.3 percent of the 1990 section 112(c)(6) emissions inventory for mercury. In contrast, biomass- and oil-fired boilers represent approximately 0.34 percent. Consequently, we are proposing to regulate coal-fired boilers under MACT because we need these sources to meet the 90 percent requirement for mercury in section 112(c)(6). We are proposing to regulate biomass-fired and oil-fired types of boilers under GACT to meet the 90 percent requirement for mercury in section 112(c)(3).

We solicit comment on whether we should nevertheless establish MACT-based mercury emission standards for all boilers in this category. In your comments, please explain the basis for your position and provide any supporting documentation.

The "maximum achievable control technology" or "MACT" regulation required by CAA section 112(d)(2) or (4) can be based on the emissions reductions achievable through application of measures, processes, methods, systems, or techniques including, but not limited to: (1)

Reducing the volume of, or eliminating emissions of, such pollutants through process changes, substitutions of materials, or other modifications; (2) enclosing systems or processes to eliminate emissions; (3) collecting, capturing, or treating such pollutants when released from a process, stack, storage or fugitive emission point; (4) design, equipment, work practices, or operational standards as provided in CAA section 112(h); or (5) a combination of the above.

The MACT floor is the minimum control level allowed for NESHAP and is defined under CAA section 112(d)(3). For new sources, MACT based standards cannot be less stringent than the emission control achieved in practice by the best-controlled similar source, as determined by the Administrator. The MACT based standards for existing sources can be less stringent than standards for new sources, but they cannot be less stringent than the average emission limitation achieved by the best performing 12 percent of existing sources in the category or subcategory (for which the Administrator has emission information) for source categories and subcategories with 30 or more sources, or the best performing 5 sources for categories and subcategories with fewer than 30 sources (CAA section 112(d)(3)(A) and (B)).

Although emission standards are often structured in terms of numerical emissions limits, alternative approaches are sometimes necessary and authorized pursuant to CAA section 112. For example, in some cases, physically measuring emissions from a source may be not practicable due to technological and economic limitations. CAA section 112(h) authorizes the Administrator to promulgate a design, equipment, work practice, or operational standard, or combination thereof, consistent with the provisions of CAA sections 112(d) or (f), in those cases where, in the judgment of the Administrator, it is not feasible to prescribe or enforce an emission standard. CAA section 112(h)(2) provides that the phrase "not feasible to prescribe or enforce an emission standard" includes the situation in which the Administrator determines that * * * the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.

As noted above, we listed industrial coal combustion, industrial oil combustion, industrial wood combustion, commercial coal combustion, commercial oil combustion, and commercial wood combustion under CAA section 112(c)(6) based on the source categories' contribution of mercury and polycyclic organic matter (POM). We listed these same categories under section 112(c)(3) for their contribution of mercury, arsenic, beryllium, cadmium, lead, chromium, manganese, nickel, polycyclic organic matter (POM) (as 7–PAH (polynuclear aromatic hydrocarbons)), ethylene dioxide, and polychlorinated biphenyls (PCB).

We have developed proposed standards to reflect the application of MACT for mercury from coal-fired area source boilers and POM from all area source boilers under section 112(c)(6) and have applied GACT for the other pollutants noted above.

B. What source categories are affected by the proposed standards?

The source categories affected by the proposed standards are industrial boilers and commercial and institutional boilers. Both source categories were included in the area source list published on July 19, 1999 (64 FR 38721). The inclusion of these two source categories on the CAA section 112(c)(3) area source category list is based on 1990 emissions data, as EPA used 1990 as the baseline year for that listing. We describe above the pollutants that formed the basis of the listings.

This proposed rule would apply to all existing and new industrial boilers, institutional boilers, and commercial boilers located at area sources. The industrial boiler source category includes boilers used in manufacturing, processing, mining, refining, or any other industry. The commercial boiler source category includes boilers used in commercial establishments such as stores/malls, laundries, apartments, restaurants, and hotels/motels. The institutional boiler source category includes boilers used in medical centers (*e.g.,* hospitals, clinics, nursing homes), educational and religious facilities (*e.g.,* schools, universities, churches), and municipal buildings (*e.g.,* courthouses, prisons).

Boiler means an enclosed combustion device having the primary purpose of recovering thermal energy in the form of steam or hot water.

C. What is the relationship between this proposed rule and other related national emission standards?

This proposed rule regulates industrial boilers and institutional/commercial boilers that are area sources of HAP. Today, in a parallel action, a NESHAP for industrial, commercial, and institutional boilers located at major sources is being proposed reflecting application of MACT. The major source NESHAP regulates emissions of particulate matter (PM) (as a surrogate for non-mercury metals), mercury, hydrogen chloride (HCl)(as a surrogate for acid gases), dioxins/furans, and carbon monoxide (CO) (as a surrogate for non-dioxin organic HAP) from existing and new major source boilers.

This proposed rule covers boilers located at area source facilities. In addition to the major source MACT for boilers being issued today and this rule, the Agency is also issuing emission standards today pursuant to CAA section 129 for commercial and industrial solid waste incineration units. In a parallel action, EPA is proposing a solid waste definition rulemaking pursuant to Subtitle D of RCRA. That action is relevant to this proceeding because if an industrial, commercial, or institutional unit located at an area source combusts secondary materials that are "solid waste," as that term is defined by the Administrator under RCRA, those units would be subject to section 129 of the CAA, not section 112.

As background, in 2007, the United States Court of Appeals for the District of Columbia Circuit (DC Circuit) vacated the CISWI Definitions Rule, which EPA issued pursuant to CAA section 129. The court found that the definitions in that rule were inconsistent with the CAA. Specifically, the Court held that the term "solid waste incineration unit" in CAA Section 129(g)(1) "unambiguously include[s] among the incineration units subject to its standards any facility that combusts any commercial or industrial solid waste material at all—subject to the four statutory exceptions identified [in CAA Section 129(g)(1)]." *NRDC* v. *EPA,* 489 F.3d at 1257–58.

Based on the information available to the Agency, we believe that the boilers that are subject to this area source rule combust coal, oil, and biomass. EPA does not believe that the boilers subject to this rule combust any non-hazardous secondary materials, whether they are considered a solid waste or not. If you are aware of such materials being combusted at these boilers, please provide specific information as to the type of secondary material being combusted and at what type of facilities and in what quantities. If the final form of the solid waste definition results in any secondary materials being considered solid waste it will be important to know whether units are burning those materials, because that would result in those units becoming incinerators subject to regulation under section 129 and no longer being considered boilers.

There is also another CAA regulation that is relevant in that they apply to some of the affected sources in this rule. For example, in 1986, EPA codified new source performance standards (NSPS) for industrial, commercial, and institutional boilers (40 CFR part 60, subparts Db and Dc) and revised portions of them in 1999 and 2006. The NSPS regulates emissions of PM, sulfur dioxide (SO_2), and nitrogen oxides from boilers constructed after June 19, 1984. Sources subject to the NSPS that are located at area source facilities are also subject to this proposed rule because this proposed rule regulates HAP. In developing this proposal, we have streamlined the monitoring and recordkeeping requirements to avoid duplicating requirements in the NSPS.

D. How did we gather information for this proposed rule?

We gathered information for this proposed rule from States' boiler inspection lists, company Web sites, published literature, State permits, current State and Federal regulations, and from an Information Collection Request (ICR) conducted for the major source NESHAP.

We developed an initial nationwide population of area source boilers based on boiler inspector databases from 13 States. The boiler inspector databases include steam boilers that are required to be inspected for safety or insurance purposes. We classified the area source boilers to NAICS codes based on the "name" of the facility at which the boiler was located. However, many of the boilers in the boiler inspector database could not be readily assigned to an NAICS code.

We reviewed State and other Federal regulations that apply to the area sources in the source categories for information concerning existing HAP emission control approaches. For example, as noted above, the NSPS for small industrial, commercial, and institutional boilers in 40 CFR part 60, subpart Dc apply to boilers at some area sources. Similarly, permit requirements established by the Ohio, Illinois, Vermont, New Hampshire, and Maine air regulatory agencies apply to some area sources. We also reviewed standards for boilers at major sources that would be appropriate for and transferable to boilers at area sources. For example, we determined that management practices, such as, annual tune-ups and operator training applicable to major source boilers are equally feasible for boilers at area sources.

E. How are the area source boiler HAP addressed by this proposed rule?

As explained above, industrial coal combustion, industrial oil combustion, industrial wood combustion, commercial coal combustion, commercial oil combustion, and commercial wood combustion are listed under CAA section 112(c)(6) due to contributions of mercury and POM and these same categories are listed under CAA section 112(c)(3) for their contribution of mercury, arsenic, beryllium, cadmium, lead, chromium, manganese, nickel, POM, ethylene dioxide, and PCB.

With respect to the 112(c)(3) pollutants, we used surrogates because, as explained below, it was not practical to establish individual standards for each specific HAP. We grouped the 112(c)(3) pollutants, which formed the basis for the listing of these two source categories, into three common groupings: mercury, non-mercury metallic HAP (arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel), and organic HAP (POM, ethylene dichloride, and PCB). In general, the pollutants within each group have similar characteristics and can be controlled with the same techniques.

For the non-mercury metallic HAP, we selected PM as a surrogate. The inherent variability and unpredictability of the non-mercury metal HAP compositions and amounts in fuel has a material effect on the composition and amount of non-mercury metal HAP in the emissions from the boiler. As a result, establishing individual numerical emissions limits for each non-mercury HAP metal species is difficult given the level of uncertainty about the individual non-mercury metal HAP compositions of the fuels that will be combusted. An emission characteristic common to all boilers is that the non-mercury metal HAP are a component of the PM contained in the fly ash emitted from the boiler. A sufficient correlation exists between PM and non-mercury metallic HAP to rely on PM as a surrogate for these HAP and for their control. Therefore, the same control techniques that would be used to control the fly-ash PM will control non-mercury metallic HAP. Emissions limits established to achieve control of PM will also achieve control of non-mercury metal HAP. Furthermore, establishing separate standards for each individual HAP would impose costly and significantly more complex compliance and monitoring requirements and achieve little, if any, HAP emissions reductions beyond what would be achieved using the surrogate pollutant approach.

For organic HAP, we selected CO as a surrogate for organic compounds, including POM, emitted from the various fuels burned in boilers. The presence of CO is an indicator of incomplete combustion. A high level of CO in emissions is an indicator of incomplete combustion and, thus, a potential indication of elevated organic HAP emissions. Monitoring equipment for CO is readily available, which is not the case for organic HAP. Also, it is significantly easier and less expensive to measure and monitor CO emissions than to measure and monitor emissions of each individual organic HAP. We considered other surrogates, such as total hydrocarbon (THC), but lacked data on emissions and permit limits for area source boilers. Therefore, using CO as a surrogate for organic urban HAP is a reasonable approach because minimizing CO emissions will result in minimizing organic urban HAP emissions.

Based on these considerations, we are proposing GACT standards for PM (as a surrogate for the individual urban metal HAP), CO (as a surrogate pollutant for the individual urban organic HAP), and mercury from biomass-fired and oil-fired boilers. We are proposing MACT standards for mercury from coal-fired boilers and for POM from all boilers.

III. Clarification of the Source Category List

The Industrial Boilers and the Institutional/Commercial Boilers area source categories were listed under section 112(c)(3) of the CAA. EPA needs to establish emission standards for area source boilers for the following urban HAP in order to meet the section 112(c)(3) 90 percent requirement for these HAP: mercury, arsenic, beryllium, cadmium, lead, chromium, manganese, nickel, POM (as 7–PAH), ethylene dioxide, and PCB. Natural gas-fired area source boilers do not emit any of the urban HAP identified above. Therefore, regulation of gas-fired area source boilers is not necessary to meet the 90 percent requirement under section 112(c)(3) for these HAP. For the reason stated above, pursuant to section 112(c)(3) of the CAA, we are proposing emission standards for the above mentioned HAP for area source boilers fired by coal, oil, and wood, but not standards for boilers fired by natural gas.

IV. Summary of This Proposed Rule

A. Do the proposed standards apply to my source?

This proposed rule applies to you if you own or operate a boiler combusting coal, biomass, or oil located at an area source. The standards do not apply to boilers that are subject to another standard under 40 CFR part 63 or to a standard developed under CAA section 129.

This proposed rule applies to you if you own or operate a boiler combusting natural gas, located at an area source, which switches to combusting coal, biomass, or oil after the date of proposal.

B. What is the affected source?

The affected source is the collection of all existing boilers within a subcategory located at an area source facility or each new boiler located at an area source facility.

C. When must I comply with the proposed standards?

The owner or operator of an existing source would be required to comply with the rule no later than 3 years after the date of publication of the final rule in the **Federal Register**. The owner or operator of a new source would be required to comply upon the date of publication of the final rule in the **Federal Register** or startup of the facility, whichever is later.

D. What are the proposed MACT and GACT standards?

Emission standards expressed in the form of emission limits are being proposed for new and existing area source boilers. The proposed MACT emission limits for mercury and CO (as a surrogate for POM) are presented, along with the proposed GACT standards for PM (as a surrogate for urban metals), in Table 1 of this preamble.

TABLE 1—EMISSION LIMITS FOR AREA SOURCE BOILERS

[Pounds per million British thermal units heat input]

Source	Subcategory	Particulate matter (PM)	Mercury	Carbon monoxide (CO) (ppm)
New Boiler	Coal	0.03	3.0E–06	310 (@ 7% oxygen).
	Biomass	0.03		100 (@ 7% oxygen).
	Oil	0.03		1 (@ 3% oxygen).
Existing Boiler	Coal		3.0E–06	310 (@ 7% oxygen).
	Biomass			160 (@ 7% oxygen).
	Oil			2 (@ 3% oxygen).

The emission limits for existing area source boilers are only applicable to area source boilers that have a designed heat input capacity of 10 million British thermal units per hour (MMBtu/h) or greater. If your boiler burns at least 10 percent coal on a total fuel annual heat input basis, the boiler is in the coal fuel subcategory. If your boiler burns biomass or biomass in combination with a liquid or gaseous fuel, the unit is in the biomass subcategory. If your boiler burns oil, or oil in combination with a gaseous fuel, the unit is in the oil subcategory, except if the unit burns oil only during periods of gas curtailment.

As allowed under CAA section 112(h), a work practice standard is being proposed for existing area source boilers that are units with designed heat input capacity of less than 10 MMBtu/h. The work practice standard for existing small area source boilers requires the implementation of a tune-up program.

An additional standard is being proposed for existing area source facilities having an affected boiler with a designed heat input capacity of 10 MMBtu/h or greater that requires the performance of an energy assessment, by qualified personnel, on the boiler and the facility to identify cost-effective energy conservation measures.

E. What are the Startup, Shutdown, and Malfunction (SSM) requirements?

The United States Court of Appeals for the District of Columbia Circuit vacated portions of two provisions in EPA's CAA section 112 regulations governing the emissions of HAP during periods of startup, shutdown, and malfunction (SSM). *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), *cert. denied, 2010 U.S. LEXIS 2265 (2010).* Specifically, the Court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), that are part of a regulation, commonly referred to as the "General Provisions Rule," that EPA promulgated under section 112 of the CAA. When incorporated into CAA Section 112(d) regulations for specific source categories, these two provisions exempt sources from the requirement to comply with the otherwise applicable CAA section 112(d) emission standard during periods of SSM.

Consistent with *Sierra Club* v. *EPA,* EPA has established standards in this rule that apply at all times. EPA has attempted to ensure that we have not incorporated into proposed regulatory language any provisions that are inappropriate, unnecessary, or redundant in the absence of an SSM exemption. We are specifically seeking comment on whether there are any such provisions that we have inadvertently incorporated or overlooked. We also request comment on whether there are additional provisions that should be added to regulatory text in light of the absence of an SSM exemption and provisions related to the SSM exemption (such as the SSM plan requirement and SSM recordkeeping and reporting provisions).

In establishing the standards in this rule, EPA has taken into account startup and shutdown periods and, for the reasons explained below, has not established different standards for those periods. The standards that we are proposing are daily or monthly averages. Based upon continuous emission monitoring data, obtained as part of the information collection effort for the major source boiler and process heater rulemaking, which included periods of startup and shutdown, over long averaging periods, startups and shutdowns will not affect the achievability of the standard. Boilers, especially solid fuel-fired boilers, do not normally startup and shutdown more than once per day. Thus, we are not establishing a separate emission standard for these periods because startup and shutdown are part of their routine operations and, therefore, are already addressed by the standards.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *" (40 CFR 63.2). EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times. It is reasonable to interpret section 112(d) as not requiring EPA to account for malfunctions in setting emissions standards. For example, we note that CAA section 112 uses the concept of "best performing" sources in defining MACT, the level of stringency that major source standards must meet. Applying the concept of "best performing" to a source that is malfunctioning presents significant difficulties. The goal of best performing sources is to operate in such a way as to avoid malfunctions of their units. Similarly, although standards for area sources are generally not required to be set based on "best performers," we believe that what is "generally available" should not be based on periods in which there is a "failure to operate."

Moreover, even if malfunctions were considered a distinct operating mode, we believe it would be impracticable to take malfunctions into account in setting CAA section 112(d) standards for area source boilers. As noted above, by definition, malfunctions are sudden and unexpected events and it would be difficult to set a standard that takes into account the myriad different types of malfunctions that can occur across all sources in the category. Moreover, malfunctions can vary in frequency, degree, and duration, further complicating standard setting.

In the event that a source fails to comply with the applicable CAA section 112(d) standards as a result of a malfunction event, EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not instead "caused in part by poor maintenance or careless operation." 40 CFR 63.2 (definition of malfunction).

F. What are the proposed initial compliance requirements?

For new and existing area source boilers with applicable emission limits, we are proposing that you must conduct initial stack tests or fuel analysis (for mercury) to determine compliance with the PM, mercury, and CO emission limits.

As part of the initial compliance demonstration, we are proposing that you must monitor specified operating parameters during the initial performance tests that demonstrate compliance with the PM and mercury emission limits for area source boilers with wet or dry scrubbers. The test average establishes your site-specific operating levels.

For owners or operators of existing area source boilers having a heat input capacity of less than 10 MMBtu/h, we are proposing that you must submit to the delegated authority or EPA, as appropriate, documentation that a tune-up was conducted.

For owners or operators of existing area source facilities having a boiler with a heat input capacity of 10 MMBtu/h or greater and subject to this rule, we are proposing that you submit to the delegated authority or EPA, as appropriate, documentation that the energy assessment was performed and the cost-effective energy conservation measures identified.

G. What are the proposed continuous compliance requirements?

If you demonstrate initial compliance with the emission limits by performance (stack) tests, we are proposing that you conduct stack tests on an annual basis. Furthermore, to demonstrate continuous compliance with the PM and mercury emission limits, we are proposing that you must monitor and comply with the applicable site-specific operating limits.

For area source boilers without wet scrubbers that must comply with the PM and mercury emission limits, we are proposing that you must continuously monitor opacity and maintain the opacity at or below ten percent (daily block average). Or, if the unit is controlled with a fabric filter, instead of continuously monitoring opacity, we are proposing that the fabric filter may be continuously operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during any 6-month period.

For boilers with wet scrubbers that must comply with the PM and mercury emission limits, we are proposing that you must monitor pressure drop and liquid flow rate of the scrubber and maintain the daily block averages at or above the minimum operating limits established during the performance test.

If you elected to demonstrate initial compliance with the mercury emission limit by fuel analysis, we are proposing that you conduct a monthly fuel analysis and maintain the annual average at or below the limit indicated in Table 1 of this preamble.

For boilers that demonstrate compliance with the PM and mercury emission limits by performance (stack) tests, we propose that you must maintain monthly fuel records that demonstrate that you burned no new fuel type or new mixture (monthly average) as set during the performance test. If you plan to burn a new fuel type or new mixture than what was burned during the initial performance test, then we are proposing that you must conduct a new performance test to demonstrate continuous compliance with the PM emission limit and mercury emission limit.

For boilers with heat input capacities equal to or greater than 100 MMBtu/hr, we propose that you must continuously monitor CO and maintain the daily average CO emissions at or below the limits indicated in Table 1 to demonstrate compliance with the CO emission limits at all times.

H. What are the proposed notification, recordkeeping and reporting requirements?

All new and existing sources would be required to comply with some requirements of the General Provisions (40 CFR part 63, subpart A), which are identified in Table 6 of this proposed rule. The General Provisions include specific requirements for notifications, recordkeeping, and reporting. If performance tests are required under this proposed rule, then the notification and reporting requirements for performance tests in the General Provisions would also apply.

Each owner or operator would be required to submit a notification of compliance status report, as required by 40 CFR 63.9(h) of the General Provisions. This proposed rule requires the owner or operator to include in the notification of compliance status report certifications of compliance with rule requirements.

Semiannual compliance reports, as required by 40 CFR 63.10(e)(3) of subpart A, would be required only for semiannual reporting periods when a deviation from any of the requirements in the rule occurred, or any process changes occurred and compliance certifications were reevaluated.

This proposed rule would require records to demonstrate compliance with each emission limit, work practice standard, or management practice. These recordkeeping requirements are specified directly in the General Provisions to 40 CFR part 63.

Records for applicable management practices must be maintained. Specifically, the owner or operator must keep records of the dates and the results of each boiler tune-up.

Records of either continuously monitored parameter data for a control device if a device is used to control the emissions or continuous emission monitoring system (CEMS) data would be required.

Each owner and operator would be required to keep the following records:

(1) All reports and notifications submitted to comply with the rule;

(2) Continuous monitoring data as required in the rule;

(3) Each instance in which you did not meet each emission limit, work/management practice, and operating limit (*i.e.,* deviations from the rule);

(4) Monthly fuel use by each boiler including a description of the type(s) of fuel(s) burned, amount of each fuel type burned, and units of measure;

(5) A copy of the results of all performance tests, energy assessments, opacity observations, performance evaluations, or other compliance demonstrations conducted to demonstrate initial or continuous compliance with the rule; and

(6) A copy of your site-specific monitoring plan developed for the rule, if applicable.

Typically, records would be retained for at least 5 years. In addition, monitoring plans, operating and maintenance plans, and other plans would be updated as necessary and kept for as long as they are still current.

I. Submission of Emissions Test Results to EPA

Compliance test data are necessary for many purposes including compliance determinations, development of emission factors, and determining annual emission rates. EPA has found it burdensome and time consuming to collect emission test data because of varied locations for data storage and varied data storage methods.

One improvement that has occurred in recent years is the availability of stack test reports in electronic format as a replacement for bulky paper copies.

In this action, we are taking a step to improve data accessibility for stack tests (and in the future continuous monitoring data). Boiler area sources would be required to submit to WebFIRE (an EPA electronic database) an electronic copy of stack test reports as well as process data. Data entry requires only access to the Internet and is expected to be completed by the stack testing company as part of the work that it is contracted to perform.

Please note that the proposed requirement to submit source test data electronically to EPA would not require any additional performance testing. In addition, when a facility submits performance test data to WebFIRE, there would be no additional requirements for data compilation; instead, we believe industry would greatly benefit from improved emissions factors, fewer information requests, and better regulation development as discussed below. Because the information that would be reported is already required in the existing test methods and is necessary to evaluate the conformance to the test methods, facilities would already be collecting and compiling these data. One major advantage of submitting source test data through the Electronic Reporting Tool (ERT), which was developed with input from stack testing companies (who already collect and compile performance test data electronically), is that it would provide a standardized method to compile and store all the documentation required by this proposed rule. Another important benefit of submitting these data to EPA at the time the source test is conducted is that these data should reduce the effort involved in data collection activities in the future for these source categories. This results in a reduced burden on both affected facilities (in terms of reduced manpower to respond to data collection requests) and EPA (in terms of preparing and distributing data collection requests). Finally, another benefit of submitting these data to WebFIRE electronically is that these data will greatly improve the overall quality of the existing and new emissions factors by supplementing the pool of emissions test data upon which emissions factors are based and by ensuring that data are more representative of current industry operational procedures. A common complaint we hear from industry and regulators is that emissions factors are out-dated or not representative of a particular source category. Receiving recent performance test results would ensure that emissions factors are updated and more accurate. In summary, receiving these test data already collected for other purposes and using them in the emissions factors development program will save industry, State/local/tribal agencies, and EPA time and money.

As mentioned earlier, the electronic data base that will be used is EPA's WebFIRE, which is a Web site accessible through EPA's TTN (technology transfer network). The WebFIRE Web site was constructed to store emissions test data for use in developing emission factors. A description of the WebFIRE data base can be found at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main.* The ERT will be able to transmit the electronic report through EPA's Central Data Exchange (CDX) network for storage in the WebFIRE data base. Although ERT is not the only electronic interface that can be used to submit source test data to the CDX for entry into WebFIRE, it makes submittal of data very straightforward and easy. A description of the ERT can be found at *http://www.epa.gov/ttn/chief/ert/ert_tool.html.*

The ERT can be used to document the conducting of stack tests data for various pollutants including PM, mercury, dioxin/furan, and HCl. Presently, the ERT does not accept opacity data or CEMS data.

EPA specifically requests comment on the utility of this electronic reporting requirement and the burden that owners and operators of boiler area source facilities estimate would be associated with this requirement.

V. Rationale of This Proposed Rule

A. How did EPA determine which pollution sources would be regulated under this proposed rule?

This proposed rule regulates industrial boilers (fired by coal, biomass, or oil) and institutional and commercial boilers (fired by coal, biomass, or oil) that are located at area sources of HAP.

Boilers that are used specifically for research and development are not regulated. However, boilers that only provide steam to a process or for heating at a research and development facility are still subject to this proposed rule.

B. How did EPA determine the subcategories for this proposed rule?

The CAA allows EPA to divide source categories into subcategories when differences between given types of units lead to corresponding differences in the nature of emissions or the technical feasibility of applying emission control techniques. The design, operating, and emissions information that EPA reviewed during the major source rulemaking indicates the need to subcategorize boilers based on the boiler type.

Boiler systems are designed for specific fuel types (*e.g.,* coal, biomass, or oil) and will encounter problems if a fuel with characteristics other than those originally specified is fired. Most boilers can only achieve full load on the fuel or fuels for which they were specifically designed. Changes to the fuel type would often require extensive changes to the fuel handling and feeding system. Additionally, the burners and combustion chamber would need to be redesigned and modified to handle different fuel types and account for increases or decreases in the fuel volume and shape. In some cases, the changes may reduce the capacity and efficiency of the boiler. An additional effect of these changes would be extensive retrofit costs.

Emissions from boilers burning coal, biomass, and oil will also differ. Boilers emit a number of urban HAP. In general, HAP formation is dependent upon the composition of the fuel. The combustion quality and temperature also play an important role. The fuel dependent urban HAP emissions from boilers are metals, including mercury. These fuel dependent HAP emissions generally can be controlled by either changing the fuel property before combustion or by removing the HAP from the flue gas after combustion. Organic HAP, on the other hand, are formed from incomplete combustion and are much less influenced by the characteristics of the fuel being burned. The degree of combustion may be greatly influenced by three general factors: time, turbulence, and temperature. These factors are a function of the design of the boiler which is dependent in part on the type of fuel being burned.

Because these different types of boilers have different emission characteristics which may influence the feasibility and effectiveness of emission control, we are proposing to subcategorize them as follows: boilers designed to fire coal, boilers designed to fire biomass, and boilers designed to fire oil in order to account for these differences in emissions. The coal-fired subcategory includes boilers burning greater than 10 percent coal on an annual fuel heat input basis. The biomass fuel subcategory includes units burning any biomass but not more than 10 percent coal on an annual fuel heat input basis. The oil subcategory includes all remaining boilers.

In summary, we have identified three subcategories of boilers located at area sources: (1) Boilers designed for coal firing, (2) boilers designed for biomass firing, and (3) boilers designed for oil firing.

C. What surrogates are we using?

As explained above, EPA is proposing emission standards for the two source categories in this proposed rule. For mercury from coal-fired area source boilers and POM from all area source boilers, EPA is proposing these standards under CAA sections 112(d)(2) and 112(h). For the other urban HAP which formed the basis of the CAA section 112(c)(3) listing, EPA is proposing standards pursuant to CAA section 112(d)(5).

In selecting the proposed emission standards, we are using PM as a surrogate for the non-mercury metallic urban HAP (arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel). The inherent variability and unpredictability of the non-mercury metal HAP compositions and amounts in fuel have a material effect on the composition and amount of non-mercury metal HAP in the emissions from the boiler. As a result, establishing individual numerical emissions limits for each non-mercury HAP metal species is difficult given the level of uncertainty about the individual non-mercury metal HAP compositions of the fuels that will be combusted. An emission characteristic common to all boilers is that the non-mercury metal HAP are a component of the PM contained in the fly ash emitted from the boiler. A sufficient correlation exists between PM and non-mercury metallic HAP to rely on PM as a surrogate for these HAP and for their control. Therefore, the same control techniques that would be used to control the fly-ash PM will control non-mercury metallic HAP. Emissions limits established to achieve control of PM will also achieve control of non-mercury metal HAP. Consequently, we used PM as a surrogate for the non-mercury metal urban HAP in establishing emissions limits. The use of PM as a surrogate will also eliminate the cost of performance testing to comply with numerous standards for individual non-mercury metals.

We looked at mercury separately from other metallic urban HAP due to its different chemical characteristics and applicable controls.

For the organic urban HAP listed for these source categories (POM, acetaldehyde, acrolein, dioxins, PCB, and formaldehyde), we used CO as a surrogate to represent the organic urban HAP emitted from the boilers. The presence of CO is an indicator of incomplete combustion. A high level of CO in emissions is an indicator of incomplete combustion and, thus, a potential indication of elevated organic HAP emissions. Monitoring equipment for CO is readily available, which is not the case for organic HAP. Also, it is significantly easier and less expensive to measure and monitor CO emissions than to measure and monitor emissions of each individual organic HAP. We considered other surrogates, such as THC, but lacked data on emissions and permit limits for area source boilers. Therefore, using CO as a surrogate for organic urban HAP is a reasonable approach because minimizing CO emissions will result in minimizing organic urban HAP emissions.

D. How did EPA determine the proposed standards for existing units?

Both industrial boilers and institutional/commercial boilers have been on the list of CAA section 112(c)(6) source categories for mercury and POM. That section requires MACT standards for each of the pollutants needed to achieve regulation of 90 percent of the emissions of the relevant pollutant. As previously noted, the CAA allows EPA to establish standards under GACT instead of MACT for urban HAP we propose to regulate to fulfill CAA section 112(c)(3).

As discussed previously, CAA section 112(h) allows the Administrator to promulgate a design, equipment, work practice, or operational standard, or combination thereof, in certain cases where, in the judgment of the Administrator, it is not feasible to prescribe or enforce an emission standard under CAA section 112(d). These cases include the situation in which the application of measurement methodology to a particular class of sources is not practicable due to technical and economic limitations.

As we establish emission standards for each source category listed pursuant to CAA section 112(c)(6), we learn more about the source category. As part of our analysis, we examine the available information about the source category, and we re-examine the inventory associated with the original listing. We continue to believe that we must regulate POM from coal-fired, biomass-fired, and oil-fired area source boilers in order to meet the requirement in section 112(c)(6), and propose below MACT-based limits for POM for all categories. However, based on the information we have learned to date as we are developing standards for various source categories, such as major source boilers, gold mines, commercial and industrial solid waste incinerators, and other categories, we believe that we only need coal-fired area source boilers to meet the 90 percent requirement set forth in section 112(c)(6) for mercury. Therefore, we propose as our primary option MACT-based controls for mercury only for coal-fired boilers.

With respect to mercury from area source boilers classified as biomass-fired or oil-fired, as well as with respect to other urban HAP besides POM, we have developed proposed standards that reflect GACT for these two area source categories.

1. MACT Analysis for Mercury From Coal-Fired Boilers and POM

All standards established pursuant to CAA section 112(d)(2) must reflect MACT, the maximum degree of reduction in emissions of air pollutants that the Administrator, taking into consideration the cost of achieving such emissions reductions, and any non-air quality health and environmental impacts and energy requirements, determined is achievable for each category or subcategory. For existing sources, MACT cannot be less stringent than the average emission limitation achieved by the best performing 12 percent of existing sources in the category or subcategory for categories or subcategories with 30 or more sources. This requirement constitutes the "MACT floor" for existing area source boilers. EPA may not consider cost in determining the MACT floor. EPA must consider cost, non-air quality health and environmental impacts, and energy requirements in evaluating whether it is appropriate to set a standard more stringent than the MACT floor (beyond-the-floor controls).

a. MACT Floor Analysis for Mercury and POM

The approach selected for determining the MACT floors is based on estimating the emissions levels achieved on average by the best 12 percent of existing sources, for which we have information. In terms of developing MACT emission limits for area source boilers, we have:

—No emission data for POM,
—Limited emission data (nine coal-fired boilers) for mercury,
—No State regulations applicable for mercury or POM,
—No State permits specific for mercury or POM,
—No surrogate for mercury, but CO as a surrogate for POM,
—Emission data on four coal-fired area source boilers using add-on control technology for mercury,
—Limited emission data for CO (5 coal-fired boilers, 30 wood-fired boilers, 68 oil-fired boilers),
—A few State permits with CO limits for coal, oil, and wood-fired area source boilers,

The MACT floor limits for each of the HAP and HAP surrogates (mercury and CO) are calculated based on the performance of the lowest emitting (best performing) sources in each of the subcategories. We ranked all of the sources for which we had data based on their emissions and identified the lowest emitting 12 percent of the sources for each HAP.

We first considered whether fuel switching would be an appropriate control option for sources in each subcategory. We considered the feasibility of fuel switching to other fuels used in the subcategory and to fuels from other subcategories. This consideration included determining whether switching fuels would achieve lower HAP emissions. A second consideration was whether fuel switching could be technically achieved by boilers in the subcategory considering the existing design of boilers. We also considered the availability of various types of fuel.

After considering these factors, we determined that fuel switching was not an appropriate control technology for purposes of determining the MACT floor level of control for any subcategory. This decision was based on the overall effect of fuel switching on HAP emissions, technical and design considerations discussed previously in this preamble, and concerns about fuel availability. This determination is discussed in the memorandum "Development of Fuel Switching Costs and Emission Reductions for Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Area Source" located in the docket.

We used the emissions data for those best performing affected sources to determine the emission limits to be proposed, with an accounting for variability. EPA must exercise its judgment, based on an evaluation of the relevant factors and available data, to determine the level of emissions control that has been achieved by the best performing sources under variable conditions. The Court has recognized that EPA may consider variability in estimating the degree of emission reduction achieved by best-performing sources and in setting MACT floors. See *Mossville Envt'l Action Now* v. *EPA,* 370 F.3d 1232, 1241–42 (DC Cir 2004) (holding EPA may consider emission variability in estimating performance achieved by best-performing sources and may set the floor at level that best-performing source can expect to meet "every day and under all operating conditions").

To calculate the achieved emission limit, including variability, we used the equation:

$$UPL = \bar{x} + t(0.99, n-1) \times \sqrt{s^2 \times \left(\frac{1}{n} + \frac{1}{m}\right)}$$

Where:

n = the number of test runs
m = the number of test runs in the compliance average
s = standard deviation of emission data
t(0.99, n − 1) = the t-statistic
x = emissions data average

Specifically, the MACT floor limit is an upper prediction limit (UPL) calculated with the Student's t-test using the TINV function in Microsoft Excel. The Student's t-test has also been used in other EPA rulemakings in accounting for variability. A prediction interval for a future observation is an interval that will, with a specified degree of confidence, contain the next (or some other pre-specified) randomly selected observation from a population. In other words, the prediction interval estimates what future values will be, based upon present or past background samples taken. Given this definition, the UPL represents the value which we can expect the mean of 3 future observations (3-run average) to fall below, based upon the results of an independent sample from the same population. That is, if we were to randomly select a future test condition from any of these sources (*i.e.,* average of 3 runs), we can be 99 percent confident that the reported level will fall at or below the UPL value. To calculate the UPL, we used the average (or sample mean) and sample standard deviation (SD), which are two statistical measures calculated from the sample data. The average is the central value of a data set, and the SD is the common measure of the dispersion of the data set around the average.

Based on this limited available information, the MACT floor analyses for the three subcategories (coal, biomass, and oil) are discussed below.

1. *Existing area source boilers designed for coal firing:*

Mercury—The total number of coal-fired area source boilers for which we have actual mercury emission data is 9. Thus, the top 12 percent is based on emissions from two boilers. The average mercury emission level of the top 12 percent is 1.3 pounds per trillion Btu (lb/TBtu). The SD of test runs in the top 12 percent boilers is 0.322. Therefore, the 99 percent UPL level is 2.5 lb/TBtu. The resulting MACT floor mercury limit for existing coal-fired area source boilers is 2.5 lb/T Btu (rounded to 0.000003 lb/

million Btu). No fuel analysis data from boilers in the top 12 percent were available for assessing the impact of fuel variability on mercury emissions.

POM—None of the States for which we have an inventory have an applicable emission limit specifically for POM or CO. However, one State (New Jersey) does have standards for CO, but for boilers the size of coal-fired area source boilers, the requirement is actually a work practice standard for CO (*i.e.,* boiler tune-up). For small (less than 50 MMBtu/h) boilers, the New Jersey requirement is to maintain and operate the source in accordance with manufacturer specifications.

The available State permits obtained for coal-fired area source boilers limiting CO emissions were for 12 units located in Ohio (3 units), California (1 unit), and Illinois (8 units). We also obtained CO emission data from 5 coal-fired area source boilers as part of the information collection effort for the major source NESHAP. Therefore, the top 12 percent is made up of three boilers. The average CO level of the top 12 percent is 162 parts per million (ppm) at 3 percent oxygen. The SD of the run data in top 12 percent boilers is 92.1 ppm. Therefore, the 99 percent UPL level is 390 ppm at 3 percent oxygen. The resulting MACT floor CO limit for existing coal-fired area source boilers is 310 ppm at 7 percent oxygen. We correct to 7 percent oxygen because that is typically in the oxygen range that coal-fired boilers operate and we rounded up to the nearest 10 ppm.

2. *Existing area source boilers designed for biomass firing:*

POM—None of the States for which we have an inventory have an applicable emission limit specifically for POM or CO. Actual CO emission data were available from the National Forest Service's Fuels for Schools program for 14 wood-fired boilers. Also, State permits limiting CO emissions from biomass boilers were obtained on another 24 biomass-fired area source boilers. We also obtained CO emission test data from 26 biomass-fired area source boilers as part of the major source ICR survey.

The top 12 percent is made up of 8 boilers. The average CO level of the top 12 percent is 80.6 ppm at 3 percent oxygen. The SD of the top 12 percent boilers is 73.5 ppm. The 99 percent UPL is 192 ppm at 3 percent oxygen, rounded up to 200 ppm. Biomass-fired boilers typically operate at around 7 percent oxygen. Therefore, the MACT floor level is 160 ppm CO at 7 percent oxygen.

3. *Existing area source boilers designed for oil firing:*

POM—None of the States for which we have an inventory have an applicable emission limit specifically for POM or CO. Actual CO emission data were available from 68 oil-fired area source boilers responding to the Boiler MACT ICR. State permits limiting CO emissions from oil-fired area source boilers were obtained on 56 oil-fired area source boilers.

The top 12 percent is made up of 15 boilers. The average CO level of the top 12 percent is 1 ppm at 3 percent oxygen. Based on the test runs from these 15 best performing units, the 99 percent UPL level is 2 ppm at 3 percent oxygen. Therefore, the MACT floor level is 2 ppm CO at 3 percent oxygen. Because oil-fired boilers typically operate at around 3 percent oxygen, additional oxygen content correction was not necessary.

4. Work Practice Standards for Smaller Boilers

As previously discussed, CAA section 112(h)(1) states that the Administrator may prescribe a work practice standard or other requirements, consistent with the provisions of CAA sections 112(d) or (f), in those cases where, in the judgment of the Administrator, it is not feasible to enforce an emission standard. CAA section 112(h)(2)(B) further defines the term "not feasible" to mean when "the application of measurement technology to a particular class of sources is not practicable due to technological and economic limitations."

The standard reference methods for measuring emissions of mercury, CO (as a surrogate for POM), and PM (as a surrogate for urban non-mercury metals) are EPA Methods 29, 10, and 5 of 40 CFR part 60 appendices A–8, A–4, and A–3, respectively. These methods are reliable and relatively inexpensive. However, the methods are not applicable for sampling small diameter (less than 12 inches) stacks. For example, in these small diameter stacks, the conventional Method 5 stack assembly blocks a significant portion of the cross-section of the duct and causes inaccurate measurements. Many existing area source boilers have stacks with diameters less than 12 inches. The stack diameter is generally related to the size of the boiler. Boilers that have a capacity below 10 MMBtu/h generally have stacks with diameters less than 12 inches. Also, many area source boilers do not currently have sampling ports or a platform for accessing the exhaust stack which would require an expensive modification to install sampling ports and a platform.

We conducted a cost-to-sales analysis to evaluate the economic impact of the testing and monitoring costs that area source boiler facilities would incur to demonstrate compliance with the proposed emission limits. The annual compliance costs imposed on each source is for the costs of a stack test for mercury and PM emissions and a continuous emission monitor (CEM) for CO emissions. We assumed that each establishment in each industry, commercial, or institutional sector would be associated with a single boiler. The financial impacts of potential compliance costs are assessed for representative entities in each entity sector using the ratio of compliance costs to the average representative entity revenue (cost-to-sales ratio or CSR).

The results of the analysis indicate that total compliance costs exceed 3 percent (and can reach as high as 19 percent) of the average firm revenues for 79 percent of the facilities. This indicates that the annual costs for testing and monitoring alone would have a significant adverse economic impact on these facilities. The severity of the economic impact would depend on the size of the facility. For small institutional (schools) and commercial (farms) facilities the costs would be prohibitive. This analysis is discussed in the memorandum "Cost-to-Sales Analysis of Testing and Monitoring Costs" located in the docket.

Based on this analysis, pursuant to CAA section 112(h), EPA is proposing that it is not feasible to enforce emission standards for area source boilers having a heat input capacity of less than 10 MMBtu/h because of the technological and economic limitations described above. Thus, a work practice, as discussed below, is being proposed to limit the emissions of mercury and CO (as a surrogate for POM) for existing area source boilers having a heat input capacity of less than 10 MMBTU/h. We are specifically requesting comment on whether a threshold higher than 10 MMBtu/h meets the technical and economic limitations as specified in section 112(h).

For existing area source boilers, the only work practice being used that potentially controls mercury and POM emissions is a boiler tune-up. Mercury is a fuel dependent HAP. That is, the amount of mercury emitted from the boiler depends on the amount of mercury contained in the fuel. Fuel usage can be reduced by improving the combustion efficiency of the boiler. At best, boilers may be 85 percent efficient and untuned boilers may have combustion efficiencies of 60 percent or lower. As combustion efficiency decreases, fuel usage increases to maintain energy output resulting in increased emissions.

On the other hand, POM is formed from incomplete combustion of the fuel. The objective of good combustion is to release all the energy in the fuel while minimizing losses from combustion imperfections and excess air. The combination of the fuel with the oxygen requires temperature (high enough to ignite the fuel constituents), mixing or turbulence (to provide intimate oxygen-fuel contact), and sufficient time (to complete the process), sometimes referred to as the three Ts of combustion. Good combustion practice (GCP), in terms of boilers, could be defined as the system design and work practices expected to minimize organic HAP emissions.

We have obtained information on area source boilers reported using GCP, as part of the information collection effort for the major source NESHAP. The data that we have suggests that area source boilers typically conduct boiler tune-ups. We also reviewed State regulations and permits applicable to area source boilers. The work practices listed in State regulations includes tune-ups (10 States), operator training (1 State), periodic inspections (2 States), and operation in accordance with manufacturer specifications (1 State). Of the 44 area source boilers with a capacity of less than 10 MMBtu/h that responded to EPA's information collection effort for major source NESHAP, 28 (or 64 percent) reported conducting a boiler tune-up program. Ultimately, we determined that at least 6 percent of the boilers in each of the subcategories are subject to a tune-up requirement. Therefore, the work practice of a tune-up does establish the MACT floor for mercury and POM emissions from existing area source boilers with a heat input capacity of less than 10 MMBtu/h.

A detailed discussion of the MACT floor methodology is presented in the memorandum "MACT Floor Analysis for the Industrial, Commercial, and Institutional Area Source Boilers" in the docket.

b. Beyond-the-Floor Determination for Mercury and POM.

We considered the pollution prevention and energy conservation measure of an energy assessment as a beyond-the-floor option for mercury and POM emissions. An energy assessment provides valuable information on improving energy efficiency. An energy assessment, or energy audit, is an in-depth energy study identifying all energy conservation measures appropriate for a facility given its operating parameters. An energy assessment refers to a process which involves a thorough examination of potential savings from energy efficiency improvements, pollution prevention, and productivity improvement. It leads to the reduction of emissions of pollutants through process changes and other efficiency modifications. Besides reducing operating and maintenance costs, improving energy efficiency reduces negative impacts on the environment. Improvement in energy efficiency results in decreased fuel use which results in a corresponding decrease in emissions (both HAP and non-HAP) from the boiler, but not necessarily all those present. The Department of Energy (DOE) has conducted energy assessments at selected manufacturing facilities and reports that facilities can reduce fuel/energy use by 10 to 15 percent by using best practices to increase their energy efficiency. Many best practices are considered pollution prevention because they reduce the amount of fuel combusted which results in a corresponding reduction in emissions from the fuel combustion. The most common best practice is simply tuning the boiler to the manufacturer's specification.

The one-time cost of an energy assessment ranges from $2500 to $55,000 depending on the size of the facility. If a facility elected to implement the cost-effective energy conservation measures identified in the energy assessment, it would potentially result in greater mercury and POM reduction than achieved by a boiler tune-up alone. In addition, the cost of an energy assessment is minimal, in most cases, compared to the cost for testing and monitoring to demonstrate compliance with an emission limit. Furthermore, the costs of any energy conservation improvement will be offset by the cost savings in lower fuel costs. Therefore, we decided to go beyond the MACT floor for this proposed rule for the existing area source boilers. The proposed standards for existing area source facilities with a boiler that has a capacity equal to or greater than 10 MMBtu/h for mercury and POM include the requirement of a performance of an energy assessment to identify energy conservation measures. Since there was insufficient information to determine if requiring implementation of cost-effective measures were economically feasible, we are seeking comment on this point.

In this proposed rule, we are defining a cost-effective energy conservation measure to be any measure that has a payback (return of investment) period of two years or less. This payback period was selected based on section 325(o)(2)(B)(iii) of the Energy Policy and Conservation Act which states that there is a presumption that an energy conservation standard is economically justified if the increased installed cost for a measure is less than three times the value of the first-year energy savings resulting from the measure.

We believe that an energy assessment is an appropriate beyond-the-floor control technology because it is one of the measures identified in CAA section 112(d)(2). CAA section 112(d)(2) states that "Emission standards promulgated * * * and applicable to new or existing sources * * * is achievable * * * through application of measures, processes, methods, systems or techniques including, but not limited to measures which—

(A) reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications,

The purpose of an energy assessment is to identify energy conservation measures (such as process changes or other modifications to the facility) that can be implemented to reduce the facility energy demand which would result in reduced fuel use. Reduced fuel use will result in a corresponding reduction in HAP, and non-HAP, emissions. Thus, an energy assessment, in combination with the MACT emission limits will result in the maximum degree of reduction in emissions as required by 112(d)(2). Therefore, we are proposing to require all existing sources to conduct a one-time energy assessment to identify cost-effective energy conservation measures on the boiler's energy consuming systems.

We are proposing that the energy assessment be conducted by energy professionals and/or engineers that have expertise that cover all energy using systems, processes, and equipment. We are aware of at least two organizations that provide certification of specialists in evaluating energy systems. We are proposing that a qualified specialist is someone who has successfully completed the Department of Energy's Qualified Specialist Program for all systems or a professional engineer certified as a Certified Energy Manager by the Association of Energy Engineers.

We are specifically requesting comment on: (1) Whether our estimates of the assessment costs are correct; (2) is there adequate access to certified assessors; (3) are there other organizations for certifying energy engineers; (4) are online tools adequate to inform the facility's decision to make efficiency upgrades; (5) is the definition of "cost-effective" appropriate in this context since it refers to payback of energy saving investments without regard to the impact on HAP reduction; and (6) what rate of return should be used.

A detailed description of the beyond-the-floor consideration is in the memorandum "Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Area Source Boilers" in the docket.

2. GACT Determination for Existing Area Source Boilers

As provided in CAA section 112(d)(5), we are proposing standards representing GACT for these area source boilers.

For existing coal and biomass-fired area source boilers, the add-on control technology generally being used is multiclones. We found that this technology is minimally effective in controlling urban metal HAP and has no effect on urban organic HAP.

Multiclones are mechanical separators that use velocity differential across the cyclones to separate particles. A multiclone uses several smaller diameter cyclones to improve efficiency. Multiclones have a control efficiency for PM emissions of about 75 percent. Multiclones are more efficient in collecting larger particles and their collection efficiency falls off at small particle sizes. This is a disadvantage because non-mercury metallic HAP tend to be on small size particles (*i.e.,* fine particle enrichment). Based on emission data obtained during the major source NESHAP development, multiclones have a control efficiency for non-mercury metallic HAP of only about 10 percent and have no effect on reducing mercury emissions. The cost of using multiclones (capital, testing, and monitoring) is estimated to be between $50,000 and $100,000 depending on the size of the boiler.

We also considered various pollution prevention and energy conservation options as the potential basis for GACT for the urban metal HAP and the organic urban HAP. The most common options, and generally available, are simply tuning the boiler to the manufacturer's specification. A boiler tune-up provides potential savings from energy efficiency improvements and pollution prevention. Besides reducing operating and maintenance costs, improving energy efficiency reduces negative impacts on the environment. Improvement in energy efficiency results in decreased fuel use which results in a corresponding decrease in emissions (both HAP and non-HAP) from the boiler. A boiler tune-up requirement would potentially result in the same non-mercury metallic HAP reduction as a PM emission limit based on performance of multiclones but would also reduce emissions of organic HAP. In addition, the cost of a boiler tune-up appears minimal compared to the cost for testing and monitoring to demonstrate compliance with an emission limit.

For existing oil-fired area source boilers, we found no add-on control technology being used.

Therefore, we determined that GACT for existing area source boilers with heat input capacities of 10 MMBtu/hour or greater is a management practice requiring the implementation of a boiler tune-up program. Thus, for existing area source boilers, we are proposing GACT for HAP other than mercury and POM to be a management practice requiring the implementation of a boiler tune-up program.

If we conclude that our obligations under section 112(c)(6) for mercury can be met without mercury emissions from biomass-fired or oil-fired area source boilers, we believe that several requirements of this proposed rule would be generally available to the regulated community and would provide some control of mercury and other fuel-bound pollutants at existing sources with larger boilers. For example, the requirements to optimize combustion, conduct an energy assessment, and conduct biennial tune-ups would decrease emissions of mercury because less fuel would be burned. In contrast, we do not believe that fabric filters are widely used now, would be expensive to install for small businesses, and therefore would not be considered GACT. Therefore, we seek comment on whether the various measures discussed in this preamble to reduce fuel consumption in connection with POM control and control of urban metal HAP and organic urban HAP would represent GACT for mercury emitted from biomass-fired and oil-fired area source boilers.

E. How did EPA determine the proposed standards for new units?

As noted above, we have developed the proposed standards to reflect the application of MACT for mercury and POM, and GACT for arsenic, beryllium, cadmium, lead, chromium, manganese, nickel, ethylene dioxide, and polychlorinated biphenyls (PCB).[1]

[1] The proposed emission standards will also reduce emissions of other urban HAP, which did not form the basis of the listing. Those urban HAP include benzene, acetaldehyde, acrolein, dioxins, and formaldehyde.

1. MACT Analysis for Mercury From Coal-fired Boilers and POM

The CAA specifies that MACT for new boilers shall not be less stringent than the emission control that is achieved in practice by the best-controlled similar source, as determined by the Administrator. This minimum level of stringency is the MACT floor for new units. EPA may not consider costs or other impacts in determining the MACT floor. However, EPA must consider cost, non-air quality health and environmental impacts, and energy requirements in evaluating whether it is appropriate to set a standard that is more stringent than the MACT floor (beyond-the-floor controls).

a. MACT Floor Analysis for Mercury and POM. Similar to the MACT floor process used for existing area source boilers, the approach used for determining the MACT floors for new units is based on estimating the emissions levels achieved by the best-controlled similar source, for which we have information.

1. *New area source boilers designed for coal firing:*

Mercury—We determined in the context of the major source rulemaking for boilers that fabric filters are the most effective technology employed by coal-fired industrial, commercial, and institutional boilers for controlling mercury emissions. Five coal-fired area source boilers have been identified as having a fabric filter. Based on available emission data, the best performing unit (*i.e.,* the unit having the reported lowest mercury level based on a three run test) is an area source coal-fired boiler equipped with an electrostatic precipitator (ESP). The boiler had a test average for mercury of 1.4 lb/TBtu with a SD of 0.307 to account for variability. Therefore, the resulting MACT floor mercury limit for new coal-fired area source boilers is determined to be 3.2 lb/T Btu. Since this calculated value is less stringent than the MACT floor for mercury at existing boilers designed for coal firing, the MACT floor for new sources was established to be equal to the floor for existing sources (0.000003 lb/million Btu).

POM—For POM emissions, the only control technology identified as being used on area source boilers is monitoring and maintaining CO emission levels which is associated with minimizing emissions of organic HAP (including POM). Carbon monoxide is generally an indicator of incomplete combustion because CO will oxidize to carbon dioxide if adequate oxygen is available. Therefore, controlling CO emissions can be a mechanism for ensuring combustion efficiency and may be viewed as a GCP. As discussed previously in this preamble, CO is considered a surrogate for organic HAP (including POM) emissions in this proposed rule.

None of the States for which we have an inventory have an applicable emission limit specifically for POM or CO. However, one State (New Jersey) does have standards for CO, but for boilers the size of coal-fired area source boilers, it is actually a work practice standard for CO (*i.e.,* tune-up). For small (less than 50 MMBtu/h) boilers, New Jersey's requirement is to maintain and operate the source in accordance with manufacturers' specifications.

Considering available State permit data and emission test data for coal-fired area source boilers the best controlled similar source is a coal-fired area source boiler having an average three run CO test emission level of 216 ppm at 3 percent oxygen. The calculated 99 percent UPL, to account for variability, is 640 ppm at 3 percent oxygen. Since this calculated value is less stringent than the MACT floor for CO at existing boilers designed for coal firing, the MACT floor for new sources was established to be equal to the floor for existing sources (310 ppm at 7 percent oxygen).

2. *New area source boilers designed for biomass firing:*

POM—None of the States for which we have an inventory have an applicable emission limit specifically for POM or CO. Actual CO emission data were available from the Fuels for Schools program for 14 biomass-fired boilers and from 29 biomass-fired area source boilers as part of the major source ICR survey. Also, State permits limiting CO emissions from biomass boilers were obtained on another 27 biomass-fired area source boilers. Therefore, the MACT floor for POM achieved by the best controlled similar source is based on actual CO emission data.

The average 3-run test CO level of the best controlled similar source is 38.6 ppm at 3 percent oxygen. The SD for the test runs is 14 ppm. Therefore, the 99 percent UPL is 120 ppm at 3 percent oxygen, rounded up to the nearest 10 ppm. Thus, the proposed MACT floor level is 100 ppm CO at 7 percent oxygen.

3. *New area source boilers designed for oil firing:*

POM—None of the States for which we have an inventory have an applicable emission limit specifically for POM or CO. Actual CO emission data were available on 66 oil-fired area source boilers. State permits limiting CO emissions from oil-fired area source boilers were obtained on 46 oil-fired area source boilers. Therefore, the proposed MACT floor for POM achieved by the best controlled similar source would be based on the boilers reporting the lowest CO emission level.

The CO emission level of the best performing similar source is 0.6 ppm at 3 percent oxygen. The SD of the test runs is 0.04 ppm. Therefore, the 99 percent UPL and the proposed MACT floor level is 1 ppm CO at 3 percent oxygen, rounded up to the nearest whole ppm.

A detailed description of the MACT floor determination is in the memorandum, "MACT Floor Analysis for Industrial, Commercial, and Institutional Area Source Boilers" in the docket.

4. *Appropriateness of Work Practice Standards for New Area Source Boilers:*

As previously discussed, CAA section 112(h) states that the Administrator may prescribe a work practice standard or other requirements, consistent with the provisions of CAA sections 112(d) or (f), in those cases where, in the judgment of the Administrator, it is not feasible to enforce an emission standard due to technical and economic limitations.

As was the case for existing small area source boilers, total compliance costs would likely exceed 3 percent of the average firm revenues for some new facilities. This indicates that the annual costs for testing and monitoring alone may have a significant adverse economic impact on some new facilities.

As discussed previously, the standard reference methods for measuring emissions of mercury, CO (as a surrogate for POM), and PM (as a surrogate for urban non-mercury metals) are EPA Methods 29, 10, and 5 and are not applicable for sampling small diameter stacks. We solicit comment on whether it would be technically infeasible to design sampling ports adequate for the test methods in boilers that are below a certain size.

Based on this analysis and the reason discussed below, we are not proposing a work practice under CAA section 112(h) for new area source boilers. New facilities, as opposed to existing facilities, have the added flexibility of including compliance costs into their design and planning. This would include the design and cost to provide a performance testing facility that has sampling ports adequate for the test methods and constructing the exhaust stack such that HAP emission rates can be accurately determined. In addition, a new facility has the option of fuel selection in minimizing their compliance costs.

A detailed discussion of the MACT floor methodology is presented in the memorandum "MACT Floor Analysis for the Industrial, Commercial, and Institutional Area Source Boilers" in the docket.

b. Beyond-the-floor Analysis for Mercury and POM for New Area Source Boilers. The MACT floor level of control for new units is based on the emission control that is achieved in practice by the best controlled similar source within each of the subcategories. No technologies or other HAP emission reduction approaches were identified that would achieve mercury or POM reduction greater than the new source floors for each of the subcategories.

Therefore, we decided to not go beyond the MACT floor level of control for mercury and POM emissions for new area source boilers in this proposed rule. A detailed description of the beyond-the-floor consideration is in the memorandum "Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Area Source Boilers" in the docket.

2. GACT Determination for New Area Source Boilers

The control technologies currently used by facilities in the source categories that reduce non-mercury metallic HAP and PM are fabric filters and ESP. We determined that these controls are generally available and cost effective for new area source boilers. New area source boilers with heat input capacity of 10 MMBtu/h or greater are subject to the NSPS for boilers (either subpart Db or Dc of 40 CFR part 60) which regulate emissions of PM and require performance testing. Furthermore, new coal-fired area source boilers will likely require a PM control device to comply with the proposed mercury MACT standard.

The emissions database contains PM test data for 82 area source boilers obtained from the ICR survey conducted for major sources. All of the boilers were greater than 10 million Btu per hour in size. In order to develop PM (as a surrogate for non-mercury metallic HAP) emission limits for the three subcategories, we compared the PM limits in NSPS subpart Dc with the obtained PM emission data. We considered this to be an appropriate methodology because many new area source boilers will be subject to NSPS subpart Dc. Consequently, we determined that the PM limits in the NSPS could be used to establish the PM GACT emission limit for area source boilers.

The proposed GACT PM emission level based on NSPS subpart Dc for new area source boilers is 0.03 lb/million Btu. Of the 82 area source boilers for which we have PM emission data, 11 had reported PM emission levels below 0.03 lb/million Btu.

For the organic urban HAP (acetaldehyde, acrolein, dioxins, and formaldehyde), the most effective control technology identified is minimizing CO emissions and we determined that this control is generally available and cost effective for new area source boilers. This determination is based on the fact there is no additional costs associated with proposing a CO emission limit (as a surrogate for the urban organic HAP) as GACT because it is the same as the MACT standard being proposed for these subcategories for POM.

F. How did we select the compliance requirements?

We are proposing testing, monitoring, notification, and recordkeeping requirements that are adequate to assure continuous compliance with the requirement of the rule. Those requirements are described in detail in sections IV.F to IV.H. We selected these requirements based upon our determination of the information necessary to ensure that the emission standards, work practices, and management practices are being followed and that emission control devices and equipment are maintained and operated properly. The proposed requirements ensure compliance with this proposed rule without proposing a significant additional burden for facilities that must implement them.

We are proposing that compliance with the PM and mercury emission limits be demonstrated by an initial performance test. To ensure continuous compliance with the proposed PM and mercury emission limits, this proposed rule would require continuous parameter monitoring of control devices and recordkeeping. Additionally, this proposed rule requires annual performance tests to ensure, on an ongoing basis, that the air pollution control device is operating properly and its performance has not deteriorated. If initial compliance with the mercury emission limit is demonstrated by a fuel analysis performance test, this proposed rule requires fuel analyses monthly, with compliance determined based on an annual average.

We evaluated the cost of applying PM CEMS to area source boilers. For PM CEM monitoring, capital costs were estimated to be $88,000 per unit and annualized costs were estimated to be $33,000 per unit. The estimated national annual cost would be $4.5 billion. We determined the costs would make them an unreasonable monitoring option.

We reviewed the cost information for CO CEMS provided by commenters on the NESHAP for major source boilers to make the determination on whether to require CO CEMS or conducting annual CO testing to demonstrate continuous compliance with the CO emission limit. In evaluating the available cost information, we determined that requiring CO CEMS for units with heat input capacities greater or equal to 100 MMBtu/hr is reasonable. This proposed rule requires units with heat input capacities less than 100 MMBtu/hr to conduct initial and annual performance (stack) tests.

G. Alternative MACT Standards for Consideration

Our analysis of the inventory for mercury under CAA section 112(c)(6) has led us to believe that we do not need to regulate biomass-fired and oil-fired boilers under MACT in order to meet our statutory obligations under this provision. We solicit comment on whether we should require the MACT-based emission limits on mercury emissions from larger boilers in this category if we conclude that such controls are unnecessary to meet our obligations under section 112(c)(6).

We also solicit comment on MACT-based requirements for mercury emitted from biomass-fired and oil-fired area source boilers in the event comment and further analysis of the inventory demonstrates such regulation is necessary to fulfill the 90 percent requirement under CAA section 112(c)(6) or is otherwise appropriate. We present what would be MACT below.

1. *Existing area source boilers designed for biomass firing:*

Mercury—We obtained mercury emission data from two biomass-fired area source boilers as part of the information collection effort for the major source NESHAP. Thus, the top 12 percent would be comprised of one boiler. The average mercury level of the top 12 percent is 0.36 lb/TBtu. All 3 test runs results were nondetect. The standard deviation for the three detection limits, when converted to lb/mmBtu using the heat input rates during each run, was 1.82E–09. Therefore, the resulting MACT floor mercury limit for existing biomass-fired area source boilers would be 0.37 lb/TBtu (rounded to 0.0000004 lb/MMBtu).

2. *Existing area source boilers designed for oil firing:*

Mercury—There are no available emission data, State regulations, or State permits regarding mercury emissions from oil-fired area source boilers. Available emission factors are generally the average of available data and would not reasonably represent the average of the top 12 percent best performing units. However, we have obtained mercury emission data on major source oil-fired boilers as part of the major source rulemaking. Since major source oil-fired boilers are similar in design and controls as compared to area source oil-fired boilers, we are applying the major source MACT limit of 4 lb/TBtu (0.000004 lb/MMBtu) to existing oil-fired area source boilers.

3. *New area source boilers designed for biomass firing:*

Mercury—We determined in the context of the major source rulemaking for boilers that fabric filters are the most effective technology employed by biomass-fired boilers for controlling mercury emissions. However, there is no test information on biomass-fired boilers equipped with fabric filters in which to determine control efficiency.

The average mercury level of the "best controlled" unit for which we have emission data is 0.36 lb/TBtu. All 3 test runs results were nondetect. The standard deviation for the three detection limits, when converted to lb/MMBtu using the heat input rates during each run, was 1.82E–09. Therefore, the resulting MACT floor mercury limit for existing biomass-fired area source boilers would be 0.36 lb/TBtu (0.0000004 lb/MMBtu).

4. *New area source boilers designed for oil firing:*

Mercury—There are no available emission data, State regulations, or State permits regarding mercury emissions from oil-fired area source boilers. Available emission factors are generally the average of available data and would not reasonably represent the best performing unit. However, we have obtained mercury emission data on major source oil-fired boilers as part of the major source rulemaking. Since major source oil-fired boilers are similar in design and controls as compared to area source oil-fired boilers, we are applying the major source MACT limit for new oil-fired boilers of 0.3 lb/TBtu (0.0000003 lb/MMBtu) to new oil-fired area source boilers.

H. How did we decide to exempt these area source categories from title V permitting requirements?

For the reasons described below, we are proposing to exempt from title V permitting requirements affected sources in the industrial boiler and the institutional/commercial boiler area source categories that are not certain synthetic area sources. We estimate that at least 48 synthetic area sources reduced their HAP emissions to below the major source thresholds by installing air pollution control devices. We are not proposing to exempt from title V those synthetic area sources that have reduced their HAP emissions to below the major source thresholds by installing air pollution control devices.

CAA section 502(a) provides that the Administrator may exempt an area source category (in whole or in part) from title V if the Administrator determines that compliance with title V requirements is "impracticable, infeasible, or unnecessarily burdensome" on an area source category. *See* CAA section 502(a). In December 2005, in a national rulemaking, EPA interpreted the term "unnecessarily burdensome" in CAA section 502 and developed a four-factor balancing test for determining whether title V is unnecessarily burdensome for a particular area source category, such that an exemption from title V is appropriate. See 70 FR 75320, December 19, 2005 (Exemption Rule).

The four factors that EPA identified in the Exemption Rule for determining whether title V is "unnecessarily burdensome" on a particular area source category include: (1) Whether title V would result in significant improvements to the compliance requirements, including monitoring, recordkeeping, and reporting, that are proposed for an area source category (70 FR 75323); (2) whether title V permitting would impose significant burdens on the area source category and whether the burdens would be aggravated by any difficulty the sources may have in obtaining assistance from permitting agencies (70 FR 75324); (3) whether the costs of title V permitting for the area source category would be justified, taking into consideration any potential gains in compliance likely to occur for such sources (70 FR 75325); and (4) whether there are implementation and enforcement programs in place that are sufficient to assure compliance with the NESHAP for the area source category, without relying on title V permits (70 FR 75326).

In discussing these factors in the Exemption Rule, we further explained that we considered on "a case-by-case basis the extent to which one or more of the four factors supported title V exemptions for a given source category, and then we assessed whether considered together those factors demonstrated that compliance with title V requirements would be 'unnecessarily burdensome' on the category, consistent with section 502(a) of the Act." See 70 FR 75323. Thus, in the Exemption Rule, we explained that not all of the four factors must weigh in favor of exemption for EPA to determine that title V is unnecessarily burdensome for a particular area source category. Instead, the factors are to be considered in combination, and EPA determines whether the factors, taken together, support an exemption from title V for a particular source category.

In the Exemption Rule, in addition to determining whether compliance with title V requirements would be unnecessarily burdensome on an area source category, we considered, consistent with the guidance provided by the legislative history of CAA section 502(a), whether exempting the area source category would adversely affect public health, welfare, or the environment. See 70 FR 15254–15255, March 25, 2005. As explained below, we propose that title V permitting is unnecessarily burdensome for a majority of the area sources at issue in this proposed rule. We have also determined that the proposed exemptions from title V would not adversely affect public health, welfare, and the environment. Our rationale for this decision follows here.

In considering the exemption from title V requirements for sources in the categories affected by this proposed rule, we first compared the title V monitoring, recordkeeping, and reporting requirements (factor one) to the requirements in the proposed NESHAP for the boiler area source categories. This proposed rule requires facilities to comply with either emission limits using add-on controls or process changes or implementation of certain work or management practices. This proposed rule would require direct monitoring of emissions or control device parameters, both continuous and periodic, recordkeeping that also may serve as monitoring, and deviation and other semi-annual reporting to assure compliance with this NESHAP.

The monitoring component of the first factor favors title V exemption. For the work and management practices, this proposed standard provides monitoring in the form of recordkeeping that would assure compliance with the requirements of this proposed rule. Monitoring by means other than recordkeeping for the work and management practices is not practical or appropriate. Records are required to ensure that the work and management practices are followed. This proposed rule requires continuous parameter monitoring, with periodic recording of the parameter for the required control device, to assure compliance. The records are required to be maintained in a form suitable and readily available for expeditious review, and that they are kept for at least five years, the first two of which must be onsite.

As part of the first factor, in addition to monitoring, we have considered the extent to which title V could potentially enhance compliance for area sources covered by this proposed rule through recordkeeping or reporting requirements. We have considered the various title V recordkeeping and reporting requirements, including requirements for a 6-month monitoring report, deviation reports, and an annual certification in 40 CFR 70.6 and 71.6.

For any boiler area source, this proposed NESHAP requires an Initial Notification and a Notification of Compliance Status. This proposed rule also requires facilities to certify compliance with the emission limits, work practices, and management practices. In addition, facilities must maintain records showing compliance through the required parameter monitoring and deviation requirements. The information required in the deviation reports is similar to the information that must be provided in the deviation reports required under 40 CFR 70.6(a)(3) and 40 CFR 71.6(a)(3).

We acknowledge that title V might require additional compliance requirements on these categories, but we have determined that the monitoring, recordkeeping and reporting requirements of the proposed NESHAP are sufficient to assure compliance with the provisions of the NESHAP. Given the nature of the operations at most area sources and the types of requirements in this rule, title V would not significantly improve those compliance requirements.

For the second factor, we determine whether title V permitting would impose a significant burden on the area sources in the categories and whether that burden would be aggravated by any difficulty the source may have in obtaining assistance from the permitting agency. Subjecting any source to title V permitting imposes certain burdens and costs that do not exist outside of the title V program. EPA estimated that the average cost of obtaining and complying with a title V permit was $65,700 per source for a 5-year permit period, including fees. See Information Collection Request for Part 70 Operating Permit Regulations, January 2007, EPA ICR Number 1587.07. EPA does not have specific estimates for the burdens and costs of permitting industrial, commercial, and institutional boiler area sources; however, there are certain activities associated with the part 70 and 71 rules. These activities are mandatory and impose burdens on the any facility subject to title V. They include reading and understanding permit program guidance and regulations; obtaining and understanding permit application forms; answering follow-up questions from permitting authorities after the application is submitted; reviewing and understanding the permit; collecting records; preparing and submitting monitoring reports on a 6-month or more frequent basis; preparing and submitting prompt deviation reports, as defined by the State, which may include a combination of written, verbal, and other communications methods; collecting information, preparing, and submitting the annual compliance certification; preparing applications for permit revisions every 5 years; and, as needed, preparing and submitting applications for permit revisions. In addition, although not required by the permit rules, many sources obtain the contractual services of consultants to help them understand and meet the permitting program's requirements. The ICR for part 70 provides additional information on the overall burdens and costs, as well as the relative burdens of each activity described here. Also, for a more comprehensive list of requirements imposed on part 70 sources (hence, burden on sources), see the requirements of 40 CFR 70.3, 70.5, 70.6, and 70.7.

In assessing the second factor for facilities affected by this proposal, we found that most of the facilities that would be affected by this proposed rule are small entities. These small sources lack the technical resources that would be needed to comply with permitting requirements and the financial resources that would be needed to hire the necessary staff or outside consultants. As discussed above, title V permitting would impose significant costs on these area sources, and, accordingly, we conclude that title V is a significant burden for the sources in these categories that we propose to exempt. Furthermore, given the estimated 91,300 area source facilities (including schools, hospitals, and churches) in the categories, it would likely be difficult for them to obtain sufficient assistance from the permitting authority. Thus, we conclude that factor two supports title V exemption for the sources in these categories that we propose to exempt.

The third factor, which is closely related to the second factor, is whether the costs of title V permitting for these area sources would be justified, taking into consideration any potential gains in compliance likely to occur for such sources. We explained above under the second factor that the costs of compliance with title V would impose a significant burden on many of the approximately 137,000 facilities affected by this proposed rule. We also concluded in considering the first factor that, while title V might impose additional requirements, the monitoring, recordkeeping and reporting requirements in this proposed NESHAP assure compliance with the emission standards, work practices, and management practices imposed in the NESHAP. In addition, below in our consideration of the fourth factor, we find that there are adequate implementation and enforcement programs in place to assure compliance with the NESHAP. Because the costs, both economic and non-economic, of compliance with title V are high, and the potential for gains in compliance is low, title V permitting is not justified for the sources we propose to exempt. Accordingly, the third factor supports title V exemptions for these area source categories, except as discussed below.

The fourth factor we considered in determining if title V is unnecessarily burdensome is whether there are implementation and enforcement programs in place that are sufficient to assure compliance with the NESHAP without relying on title V permits. EPA has implemented regulations that provide States the opportunity to take delegation of area source NESHAP, and we believe that State delegated programs are sufficient to assure compliance with this NESHAP. See 40 CFR part 63, subpart E (States must have adequate programs to enforce the CAA section 112 regulations and provide assurances that they will enforce the NESHP before EPA will delegate the program).

We also note that EPA retains authority to enforce this NESHAP anytime under CAA sections 112, 113, and 114. Also, States and EPA often conduct voluntary compliance assistance, outreach, and education programs (compliance assistance programs), which are not required by statute. We determined that these additional programs will supplement and enhance the success of compliance with these proposed standards. We believe that the statutory requirements for implementation and enforcement of this NESHAP by the delegated States and EPA and the additional assistance programs described above together are sufficient to assure compliance with these proposed standards without relying on title V permitting.

In light of all the information presented here, we believe that there are implementation and enforcement programs in place that are sufficient to assure compliance with the proposed standards without relying on title V permitting for the sources we are proposing to exempt.

Balancing the four factors for these area source categories strongly supports the proposed finding that title V is unnecessarily burdensome for the sources we propose to exempt. While title V might add additional compliance requirements if imposed, we believe that there would not be significant improvements to the compliance requirements in this proposed rule because the proposed rule requirements are specifically designed to assure compliance with the emission standards imposed on the area sources we propose to exempt. We further maintain that the economic and non-economic costs of compliance with title V would impose a significant burden on the sources we propose to exempt. We determined that the high relative costs would not be justified given that there is likely to be little or no potential gain in compliance if title V were required. And, finally, there are adequate implementation and enforcement programs in place to assure compliance with these proposed standards. Thus, we propose that title V permitting is "unnecessarily burdensome" for these area source categories, except as discussed below.

In addition to evaluating whether compliance with title V requirements is "unnecessarily burdensome", EPA also considered, consistent with guidance provided by the legislative history of CAA section 502(a), whether exempting these area source categories from title V requirements would adversely affect public health, welfare, or the environment. Exemption of these area source categories from title V requirements would not adversely affect public health, welfare, or the environment because the level of control would remain the same if a permit were required. The title V permit program does not impose new substantive air quality control requirements on sources, but instead requires that certain procedural measures be followed, particularly with respect to determining compliance with applicable requirements. As stated in our consideration of factor one for this category, title V would not lead to significant improvements in the compliance requirements applicable to existing or new area sources that we propose to exempt.

Furthermore, we explained in the Exemption Rule that requiring permits for the large number of area sources could, at least in the first few years of implementation, potentially adversely affect public health, welfare, or the environment by shifting State agencies resources away from assuring compliance for major sources with existing permits to issuing new permits for these area sources, potentially reducing overall air program effectiveness. Based on the above analysis, we conclude that title V exemptions for these area sources would not adversely affect public health, welfare, or the environment for all of the reasons explained above.

For the reasons stated here, we are proposing to exempt these area source categories, except for certain synthetic area sources, as explained below, from title V permitting requirements.

We have determined that it is not appropriate to exempt from Title V requirements those synthetic area sources that installed air pollution controls. Unlike many other area source categories that we have exempted from title V while implementing the requirements of CAA sections 112(c)(3) and 112(k)(3)(B), the boiler area source categories include a number of synthetic area sources that installed air pollution controls to become area sources. Synthetic area sources that installed controls represent less than one percent of the total number of sources that will be subject to the final rule. In fact, these sources are much more like the major sources of HAP that will be subject to the Boiler MACT. In addition, many of these sources are located in cities, and often in close proximity to residential and commercial centers where large numbers of people live and work. The record also indicates that many of these synthetic area sources have significantly higher emissions potential when uncontrolled than the other sources in the boiler area source categories, even those that are synthetic minor sources that took operational limits to attain area source status.

For these reasons, we believe that the additional public participation and compliance benefits of additional informational, monitoring, reporting, certification, and enforcement requirements that exist in title V should be the same for a major source that installed a control device after 1990 to become an area source as for a source that is major and installed a control device to comply with an applicable major source NESHAP, and thereby reduced emissions below major source levels (10 tpy of a single HAP and 25 tpy of total HAP). Many of the synthetic area sources that became area sources by virtue of installing add-on controls are large facilities with comprehensive compliance programs in place because their uncontrolled emissions would far exceed the major source threshold. We maintain that requiring additional public involvement and compliance assurance requirements through title V is important to ensure that these sources are maintaining their emissions at the area source level.

For these reasons above, this proposed rule requires title V permits for major sources of HAP emissions that installed controls after 1990 to become area sources of HAP emissions. We estimate that approximately 170 sources that will be subject to this rule are either required to have title V permits because of criteria pollutants or the proposed rule will require the affected area sources to obtain title V permits.

We are not requiring title V permits for sources that reduced their emissions to area source levels by taking operational restrictions, such as restricting hours of operation or production, or for natural area sources, for the reasons set forth above.

VI. Summary of the Impacts of This Proposed Rule

A. What are the air impacts?

Table 2 of this preamble illustrates, for each subcategory, the estimated emissions reductions achieved by this proposed rule (*i.e.,* the difference in emissions between an area source boiler controlled to the MACT/GACT level of control and boilers at the current baseline) for new and existing sources. Nationwide emissions of total HAP (hydrogen chloride, hydrogen fluoride, non-mercury metals, mercury, and VOC (for organic HAP) will be reduced by about 1,200 tpy for existing units and 340 tpy for new units. Emissions of mercury will be reduced by about 0.7 tpy per year for existing units and by 0.1 tpy for new units. Emissions of filterable PM will be reduced by about 6,300 tpy for existing units and 1,300 tpy for new units. Emissions of non-mercury metals (*i.e.,* antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium) will be reduced by about 210 tpy for existing units and will be reduced by 40 tpy for new units. Additionally, EPA has estimated that conducting an annual tune-up could potentially reduce emissions of organic HAP as a result of improved combustion and reduced fuel use. POM reductions are represented by 7–PAH, a group of polycyclic aromatic hydrocarbons. EPA estimates that the energy efficient work and management practices may reduce emissions of 7–PAH by 8 tpy for existing units and that the CO emission limit may reduce emissions of 7–PAH by 1 tpy for new units. A discussion of the methodology used to estimate baseline emissions and emissions reductions is presented in "Estimation of Impacts for Industrial, Commercial, and Institutional Boilers Area Source NESHAP" in the docket.

TABLE 2—SUMMARY OF HAP EMISSIONS REDUCTIONS FOR EXISTING AND NEW SOURCES (TPY)

Source	Subcategory	PM	Non mercury metals [a]	Mercury	POM [b]
Existing Units	Coal	5,350	24	0.6	0.2
	Biomass	760	10	0.003	5
	Oil	230	175	0.03	3
New Units	Coal	510	3	0.09	0.02
	Biomass	690	8	0.0003	0.5
	Oil	100	28	0.005	0.5

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

[b] POM is represented by total emissions of polycyclic aromatic hydrocarbons (7–PAH). It is assumed that compliance with work practice standard and management practice will reduce fuel usage by 1 percent, which may reduce emissions of 7–PAH by an equivalent amount.

B. What are the cost impacts?

To estimate the national cost impacts of this proposed rule for existing sources, EPA developed several model boilers and determined the cost of control for these model boilers. The EPA assigned a model boiler to each existing unit based on the fuel, size, and current controls. The analysis considered all air pollution control equipment currently in operation at existing boilers. Model costs were then assigned to all existing units that could not otherwise meet the proposed standards. The resulting total national cost impact of this proposed rule for existing units is $696 million dollars in total annualized costs. The total annualized costs (new and existing) for installing controls, conducting biennial tune-ups and an energy assessment, and implementing testing and monitoring requirements, is $1.0 billion. Table 3 of this preamble shows the total annualized cost impacts for each subcategory.

TABLE 3—SUMMARY OF ANNUAL COSTS FOR NEW AND EXISTING SOURCES

Source	Subcategory	Estimated/projected number of affected units	Total annualized cost (10^6\$/yr) [a]
Existing Units	Coal	3,710	160
	Biomass	10,958	48
	Oil	168,003	436
Facility Energy Assessment	All	....	52
New Units [b]	Coal	155	54
	Biomass	200	13
	Oil	6,424	244

[a] TAC does not include fuel savings from improving combustion efficiency.
[b] Impacts for new units assume the number of units online in the first 3 years of this rule (2010 to 2013).

Using DOE projections on fuel expenditures, as well as the history of installation dates of area source boilers in the dataset, the number of additional boilers that could be potentially constructed was estimated. The resulting total national cost impact of this proposed rule on new sources by the 3rd year, 2013, is $311 million dollars in total annualized costs. When accounting for a 1 percent fuel savings resulting from improvements to combustion efficiency, the total national cost impact on new sources is $260 million.

A discussion of the methodology used to estimate cost impacts is presented in the memorandum "Estimation of Impacts for Industrial, Commercial, and Institutional Boilers Area Source NESHAP" in the Docket.

C. What are the economic impacts?

The economic impact analysis (EIA) that is included in the RIA shows that the expected prices for industrial sectors could be 0.01 percent higher and domestic production may fall by less than 0.01 percent. Because of higher domestic prices imports may rise by less than 0.01 percent. Energy prices will not be affected.

Social costs are estimated to also be $0.5 billion in 2008 dollars. This is estimated to made up of a $0.3 billion loss in domestic consumer surplus, a $0.3 billion loss in domestic producer surplus, a $0.1 billion increase in rest of the world surplus, and a $0.1 billion net loss associated with new source costs and fuel savings not modeled in a way that can be used to attribute it to consumers and producers.

EPA performed a screening analysis for impacts on small entities by comparing compliance costs to sales/revenues (*e.g.,* sales and revenue tests). EPA's analysis found the tests were typically higher than 3 percent for small entities included in the screening analysis. EPA has prepared an Initial Regulatory Flexibility Analysis (IRFA) that discusses alternative regulatory or policy options that minimize the rule's small entity impacts. It includes key information about key results from the Small Business Advocacy Review (SBAR) panel.

Precise job effect estimates cannot be estimated with certainty. Morgenstern *et al.* (2002) identify three economic mechanisms by which pollution abatement activities can indirectly influence jobs:

- Higher production costs raise market prices, higher prices reduce consumption, and employment within an industry falls ("demand effect");
- Pollution abatement activities require additional labor services to produce the same level of output ("cost effect"); and
- Post regulation production technologies may be more or less labor intensive (*i.e.,* more/less labor is required per dollar of output) ("factor-shift effect").

Several empirical studies, including Morgenstern *et al.* (2002), suggest the net employment decline is zero or economically small (*e.g.,* Cole and Elliot, 2007; Berman and Bui, 2001). However, others show the question has not been resolved in the literature (Henderson, 1996; Greenstone, 2002). Morgenstern's paper uses a six-year panel (U.S. Census data for plant-level prices, inputs (including labor), outputs, and environmental expenditures) to econometrically estimate the production technologies and industry-level demand elasticities. Their identification strategy leverages repeat plant-level observations over time and uses plant-level and year fixed effects (*e.g.,* plant and time dummy variables). After estimating their model, Morgenstern show and compute the change in employment associated with an additional $1 million ($1987) in environmental spending. Their estimates covers four manufacturing industries (pulp and paper, plastics, petroleum, and steel) and Morgenstern, *et al.* present results separately for the cost, factor shift, and demand effects, as well as the net effect. They also estimate and report an industry-wide average parameter that combines the four industry-wide estimates and weighting them by each industry's share of environmental expenditures.

EPA has most often estimated employment changes associated with plant closures due to environmental regulation or changes in output for the regulated industry (EPA, 1999a; EPA, 2000). This analysis goes beyond what EPA has typically done in two ways. First, because the multimarket model provides estimates for changes in output for sectors not directly regulated, we were able to estimate a more comprehensive "demand effect." Secondly, parameters estimated in the Morgenstern paper were used to estimate all three effects ("demand," "cost," and "factor shift"). This transfer of results from the Morgenstern study is uncertain but avoids ignoring the "cost effect" and the "factor-shift effect."

We calculated "demand effect" employment changes by assuming that the number of jobs changes proportionally with multi-market model's simulated output changes. These results were calculated for all sectors in the EPA model that show a change in output. The total job losses are estimated to be approximately 1,000.

We also calculated a similar "demand effect" estimate that used the Morgenstern paper. To do this, we multiplied the point estimate for the total demand effect (−3.56 jobs per million ($1987) of environmental compliance expenditure) by the total environmental compliance expenditures used in the partial equilibrium model. For example, the job loss estimate is approximately 1,000 jobs (−3.56 × $0.5 billion × 0.60).[2]

We also present the results of using the Morgenstern paper to estimate employment "cost" and "factor-shift" effects (Table 1). Although using the Morgenstern parameters to estimate these "cost" and "factor-shift" employment changes is uncertain, it is helpful to compare the potential job gains from these effects to the job losses associated with the "demand" effect. Table 1 shows that using the Morgenstern point estimates of parameters to estimate the "cost" and "factor shift" employment gains may be greater than the employment losses using either of the two ways of estimating "demand" employment losses. The 95 percent confidence intervals are shown for all of the estimates based on the Morgenstern parameters. As shown, at the 95 percent confidence level, we cannot be certain if net employment changes are positive or negative.

Although the Morgenstern paper provides additional information about the potential job effects of environmental protection programs, there are several qualifications EPA considered as part of the analysis. First, EPA has used the weighted average parameter estimates for a narrow set of manufacturing industries (pulp and paper, plastics, petroleum, and steel). Absent other data and estimates, this approach seems reasonable and the estimates come from a respected peer-reviewed source. However, EPA acknowledges the proposed rule covers a broader set of industries not considered in original empirical study. By transferring the estimates to other industrial sectors, we make the assumption that estimates are similar in size. In addition, EPA assumes also that Morgenstern et al.'s estimates derived from the 1979–1991 still applicable for policy taking place in 2013, almost 20 years later. Second, the multi-market model only considers near term employment effects in a U.S. economy where production technologies are fixed. As a result, the modeling system places more emphasis on the short term "demand effect" whereas the Morgenstern paper emphasizes other important long term responses. For example, positive job gains associated with "factor shift effects" are more plausible when production choices become more flexible over time and industries can substitute labor for other production inputs. Third, the Morgenstern paper estimates rely on sector demand elasticities that are different from the demand elasticity parameters used in the multi-market model. As a result, the demand effects are not directly comparable with the demand effects estimated by the multi-market model. Fourth, Morgenstern identifies the industry average as economically and statistically insignificant effect (*i.e.,* the point estimates are small, measured imprecisely, and not distinguishable from zero). EPA acknowledges this fact and has reported the 95 percent confidence intervals in Table 1. Fifth, Morgenstern's methodology assumes large plants bear most of the regulatory costs. By transferring the estimates, EPA assumes a similar distribution of regulatory costs by plant size and that the regulatory burden does not disproportionately fall on smaller plants.

TABLE 4—EMPLOYMENT CHANGES: 2013

Estimation method	1,000 jobs
Partial equilibrium model (multiple markets) (demand effect only)	−1.
Literature-based estimate (net effect [A + B + C below])	+1 (−1 to +2).
A. *Literature-based estimate: Demand effect*	−1 (−3 to 0).
B. *Literature-based estimate: Cost effect*	+1 (0 to +2).
C. *Literature-based estimate: Factor shift effect*	+1 (0 to +2).

Note: Totals may not add due to independent rounding. 95 percent confidence intervals for literature-based estimates are shown in parenthesis.

D. What are the social costs and benefits of this proposed rule?

We estimated the monetized benefits of this proposed regulatory action to be $1.0 billion to $2.4 billion (2008$, 3 percent discount rate) in the implementation year (2013). The monetized benefits of this proposed regulatory action at a 7 percent discount rate are $910 million to $2.2 billion (2008$). Using alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts, higher and lower benefits estimates are plausible, but most of the expert-based estimates fall between these two estimates.[3] A summary of the monetized benefits estimates at discount rates of 3 percent and 7 percent is in Table 5 of this preamble.

[2] Since Morgenstern's analysis reports environmental expenditures in $1987, we make an inflation adjustment to the engineering cost analysis using GDP implicit price deflator (64.76/108.48) = 0.60).

[3] Roman *et al.,* 2008. "Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S." Environ. Sci. Technol., 42, 7, 2268—2274.

TABLE 5—SUMMARY OF THE MONETIZED BENEFITS ESTIMATES FOR THE PROPOSED BOILER AREA SOURCE RULE IN 2013

[Billions of 2008$] [1]

	Estimated emission reductions (tons per year)	Total monetized benefits (3% discount rate)	Total monetized benefits (7% discount rate)
$PM_{2.5}$	2,682	$0.96 to $2.4	$0.88 to $2.1.
$PM_{2.5}$ Precursors			
SO_2	1,539	$0.31 to $0.76	$0.28 to $0.68.
VOC	1,179	$0.01 to $0.04	$0.01 to $0.03.
Total		$1.0 to $2.4	$0.91 to $2.2.

[1] All estimates are for the implementation year (2013), and are rounded to two significant figures so numbers may not sum across rows. All fine particles are assumed to have equivalent health effects, but the benefit-per-ton estimates vary between precursors because each ton of precursor reduced has a different propensity to form $PM_{2.5}$. Benefits from reducing hazardous air pollutants (HAPs), ecosystem effects, and visibility impairment are not included.

These benefits estimates represent the total monetized human health benefits for populations exposed to less $PM_{2.5}$ in 2013 from controls installed to reduce air pollutants in order to meet these standards. These estimates are calculated as the sum of the monetized value of avoided premature mortality and morbidity associated with reducing a ton of $PM_{2.5}$ and $PM_{2.5}$ precursor emissions. To estimate human health benefits derived from reducing $PM_{2.5}$ and $PM_{2.5}$ precursor emissions, we utilized the general approach and methodology laid out in Fann *et al.* (2009).[4]

To generate the benefit-per-ton estimates, we used a model to convert emissions of direct $PM_{2.5}$ and $PM_{2.5}$ precursors into changes in ambient $PM_{2.5}$ levels and another model to estimate the changes in human health associated with that change in air quality. Finally, the monetized health benefits were divided by the emission reductions to create the benefit-per-ton estimates. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between precursors because each ton of precursor reduced has a different propensity to form $PM_{2.5}$. For example, SO_X has a lower benefit-per-ton estimate than direct $PM_{2.5}$ because it does not form as much $PM_{2.5}$, thus the exposure would be lower, and the monetized health benefits would be lower.

For context, it is important to note that the magnitude of the PM benefits is largely driven by the concentration response function for premature mortality. Experts have advised EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$ concentrations and premature mortality. For this proposed rule we cite two key empirical studies, one based on the American Cancer Society cohort study [5] and the extended Six Cities cohort study.[6] In the RIA for this proposed rule, which is available in the docket, we also include benefits estimates derived from expert judgments and other assumptions.

This analysis does not include the type of detailed uncertainty assessment found in the 2006 $PM_{2.5}$ NAAQS RIA because we lack the necessary air quality input and monitoring data to run the benefits model. However, the 2006 $PM_{2.5}$ NAAQS benefits analysis [7] provides an indication of the sensitivity of our results to various assumptions.

It should be emphasized that the monetized benefits estimates provided above do not include benefits from several important benefit categories, including reducing other air pollutants, ecosystem effects, and visibility impairment. The benefits from reducing carbon monoxide and hazardous air pollutants have not been monetized in this analysis, including reducing 39,000 tons of carbon monoxide, 0.75 ton of mercury, and 130 tons of HCl, 5 tons of HF, and 460 grams of dioxins/furans each year. Although we do not have sufficient information or modeling available to provide monetized estimates for this rulemaking, we include a qualitative assessment of the health effects of these air pollutants in the Regulatory Impact Analysis (RIA) for this proposed rule, which is available in the docket.

The social costs of this proposed rulemaking are estimated to be $0.5 billion (2008$) in the implementation year, and the monetized benefits are $1.0 billion to $2.4 billion (2008$, 3 percent discount rate) for that same year. The benefits at a 7 percent discount rate are $910 million to $2.2 billion (2008$). Thus, net benefits of this rulemaking are estimated at $500 million to $1.9 billion (2008$, 3 percent discount rate) and $400 million to $1.7 billion (2008$, 7 percent discount rate).

A summary of the monetized benefits, social costs, and net benefits at discount rates of 3 percent and 7 percent is in Table 6 of this preamble.

[4] Fann, N., C.M. Fulcher, B.J. Hubbell. 2009. "The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution." Air Qual Atmos Health (2009) 2:169–176.

[5] Pope *et al.,* 2002. "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." Journal of the American Medical Association 287:1132–1141.

[6] Laden *et al.,* 2006. "Reduction in Fine Particulate Air Pollution and Mortality." *American Journal of Respiratory and Critical Care Medicine.* 173:667–672.

[7] U.S. Environmental Protection Agency, 2006. Final Regulatory Impact Analysis: $PM_{2.5}$ NAAQS. Prepared by Office of Air and Radiation. October. Available on the Internet at *http://www.epa.gov/ttn/ecas/ria.html.*

TABLE 6—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE BOILER AREA SOURCE RULE IN 2013

[Billions of 2008$] [1]

	3% Discount rate	7% Discount rate
Proposed Option		
Total Monetized Benefits [2]	$1.0 to $2.4	$0.91 to $2.2.
Total Social Costs [3]	$0.50	$0.5.
Net Benefits	$0.5 to $1.9	$0.4 to $1.7.
Non-monetized Benefits	39,000 tons of carbon monoxide. 130 tons of HCl. 5 tons of HF. 0.75 tons of mercury. 250 tons of other metals. 470 grams of dioxins/furans. Health effects from NO_2 and SO_2 exposure. Ecosystem effects. Visibility impairment.	

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

[2] The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of directly emitted $PM_{2.5}$ and $PM_{2.5}$ precursors such as NO_X and SO_2. It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure.

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

For more information on the benefits analysis, please refer to the RIA for this rulemaking, which is available in the docket.

E. What are the water and solid waste impacts?

The EPA estimated that no additional water usage would result from the MACT floor level of control or GACT requirement. The fabric filter, multiclone or combustion control devices used to meet the standards of this proposed rule do not require any water to operate, nor do they generate any wastewater.

The EPA estimated the additional solid waste that would result from this proposed rule to be 14,300 tpy for existing sources due to the dust and flyash captured by mercury and PM control devices. The cost of handling the additional solid waste generated from existing sources is $602,000 per year. For new sources installed by 2013, the EPA estimated the additional solid waste that would result from this proposed rule to be 1,800 tpy for new sources due to the dust and flyash captured by mercury and PM control devices. The cost of handling the additional solid waste generated from existing sources is $75,900 per year. These costs are also accounted for in the control costs estimates.

A discussion of the methodology used to estimate impacts is presented in "Estimation of Impacts for Industrial, Commercial, and Institutional Boilers Area Source NESHAP" in the Docket.

F. What are the energy impacts?

The EPA expects an increase of approximately 206 million kilowatt hours (kWh) in national annual energy usage from existing sources as a result of this proposed rule. The increase results from the electricity required to operate control devices installed to meet this proposed rule, such as fabric filters. Additionally, for new sources installed by 2013, EPA expects an increase of approximately 22 million kWh in national annual energy usage in order to operate the control devices.

The Department of Energy has conducted energy assessments at selected manufacturing facilities and reports that facilities can reduce fuel/energy use by 10 to 15 percent by using best practices to increase their energy efficiency. Additionally, the EPA expects work practice standards such as boilers tune-ups and combustion controls such as new replacement burners and will improve the efficiency of boilers. The EPA estimates existing area source facilities can save 20 trillion BTU of fuel each year. For new sources online by 2013, the EPA estimates 2.3 trillion BTU per year of fuel can be conserved. This fuel savings estimates includes only those fuel savings resulting from liquid and coal fuels and it is based on the assumption that the work practice standards will achieve 1 percent improvement in efficiency.

VII. Relationship of This Proposed Action to CAA Section 112(c)(6)

CAA section 112(c)(6) requires EPA to identify categories of sources of seven specified pollutants to assure that sources accounting for not less than 90 percent of the aggregate emissions of each such pollutant are subject to standards under CAA Section 112(d)(2) or 112(d)(4). EPA has identified "Industrial Coal Combustion," "Industrial Oil Combustion," Industrial Wood/Wood Residue Combustion," "Commercial Coal Combustion," "Commercial Oil Combustion," and "Commercial Wood/Wood Residue Combustion" as source categories that emits two of the seven CAA Section 112(c)(6) pollutants: POM and mercury. (The POM emitted is composed of 16 polyaromatic hydrocarbons (PAH) and extractable organic matter (EOM).) In the **Federal Register** notice *Source Category Listing for Section 112(d)(2) Rulemaking Pursuant to Section 112(c)(6) Requirements,* 63 FR 17838, 17849, Table 2 (1998), EPA identified "Industrial Coal Combustion," "Industrial Oil Combustion," "Industrial Wood/Wood Residue Combustion," "Commercial Coal Combustion," "Commercial Oil Combustion," and "Commercial Wood/Wood Residue Combustion" as source category "subject to regulation" for purposes of CAA Section 112(c)(6) with respect to the CAA Section 112(c)(6) pollutants that these units emit.

Specifically, as byproducts of combustion, the formation of POM is effectively reduced by the combustion and post-combustion practices required to comply with the CAA Section 112 standards. Any POM that do form during combustion are further controlled by the various post-combustion controls. The add-on PM control systems (fabric filter) used to reduce mercury and/or PM emissions further reduce emissions of these organic pollutants, as is evidenced by performance data. Specifically, the emission tests obtained at currently operating major source boilers show that the proposed MACT regulations for area source boilers will reduce Hg emissions by about 86 percent. It is, therefore, reasonable to conclude that POM emissions will be substantially controlled. Thus, while this proposed rule does not identify specific numerical emission limits for POM, emissions of POM are, for the reasons noted below, nonetheless "subject to regulation" for purposes of CAA section 112(c)(6).

In lieu of establishing numerical emissions limits for pollutants such as POM, we regulate surrogate substances. While we have not identified specific numerical limits for POM, we believe CO serves as an effective surrogate for this HAP, because CO, like POM, is formed as a product of incomplete combustion.

Consequently, we have concluded that the emissions limits for CO function as a surrogate for control of POM, such that it is not necessary to propose numerical emissions limits for POM with respect to boilers to satisfy CAA Section 112(c)(6).

To further address POM and mercury emissions, this proposed rule also includes an energy assessment provision that encourages modifications to the facility to reduce energy demand that lead to these emissions.

VIII. Statutory and Executive Order Review

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities.

Accordingly, EPA submitted this action to OMB for review under EO 12866 and any changes in response to OMB recommendations have been documented in the docket for this action. For more information on the costs and benefits for this rule, please refer to Table 5 of this preamble.

B. Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to OMB under the *Paperwork Reduction Act*, 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by EPA has been assigned EPA ICR number 2253.01.

The recordkeeping and reporting requirements in this proposed rule would be based on the information collection requirements in EPA's NESHAP General Provisions (40 CFR part 63, subpart A). The recordkeeping and reporting requirements in the General Provisions are mandatory pursuant to section 114 of the CAA (42 U.S.C. 7414). All information other than emissions data submitted to EPA pursuant to the information collection requirements for which a claim of confidentiality is made is safeguarded according to CAA section 114(c) and EPA's implementing regulations at 40 CFR part 2, subpart B.

This proposed NESHAP would require applicable one-time notifications according to the NESHAP General Provisions. Facility owners or operators would be required to include compliance certifications for the work practices and management practices in their Notifications of Compliance Status. Recordkeeping would be required to demonstrate compliance with emission limits, work practices, management practices, monitoring, and applicability provisions. New affected facilities would be required to comply with the requirements for startup, shutdown, and malfunction plans/reports and to submit a compliance report if a deviation occurred during the semiannual reporting period.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $523 million. This includes 3.6 million labor hours per year at a cost of $336 million and total non-labor capital costs of $186 million per year. This estimate includes initial and annual performance tests, conducting and documenting an energy assessment, conducting and documenting a tune-up, semiannual excess emission reports, maintenance inspections, developing a monitoring plan, notifications, and recordkeeping. Monitoring, testing, tune-up and energy assessment costs were also included in the cost estimates presented in the control costs impacts estimates in section VI.B of this preamble. The total burden for the Federal government (averaged over the first 3 years after the effective date of the standard) is estimated to be 767,403 hours per year at a total labor cost of $37.6 million per year.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR part 63 are listed in 40 CFR part 9.

To comment on EPA's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques, EPA has established a public docket for this action, which includes this ICR, under Docket ID number EPA–HQ–OAR–2006–0790. Submit any comments related to the ICR to EPA and OMB. See **ADDRESSES** section at the beginning of this preamble for where to submit comments to EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Office for EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after June 4, 2010, a comment to OMB is best assured of having its full effect if OMB receives it by July 6, 2010. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act (RFA)

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. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's proposed rule on small entities, small entity is defined as: (1) A small business according to Small Business Administration (SBA) size standards by the North American Industry Classification System category of the owning entity. The range of small business size standards for the 40 affected industries ranges from 500 to 1,000 employees, except for petroleum refining and electric utilities. In these latter two industries, the size standard is 1,500 employees and a mass throughput of 75,000 barrels/day or less, and 4 million kilowatt-hours of production or less, respectively; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Because an initial screening analysis for impact on small entities indicated a likely significant impact for substantial numbers EPA convened a SBAR Panel to obtain advice and recommendation of representatives of the small entities that potentially would be subject to the requirements of this rule.

(1) Panel Process and Panel Outreach

As required by section 609(b) of the RFA, as amended by SBREFA, EPA also has conducted outreach to small entities and. On January 22, 2009 EPA's Small Business Advocacy Chairperson convened a Panel under section 609(b) of the RFA. In addition to the Chair, the Panel consisted of the Director of the Sector Policies and Programs Division within EPA's Office of Air and Radiation, the Chief Counsel for Advocacy of the Small Business Administration, and the Administrator of the Office of Information and Regulatory Affairs within the Office of Management and Budget.

As part of the SBAR Panel process we conducted outreach with representatives from 14 various small entities that would be affected by this rule. The small entity representatives (SERs) included associations representing schools, churches, hotels/motels, wood product facilities and manufacturers of home furnishings. We met with these SERs to discuss the potential rulemaking approaches and potential options to decrease the impact of the rulemaking on their industries/sectors. We distributed outreach materials to the SERs; these materials included background on the rulemaking, possible regulatory approaches, preliminary cost and economic impacts, and possible rulemaking alternatives. The Panel met with SERs from the industries that will be impacted directly by this rule on February 10, 2009 to discuss the outreach materials and receive feedback on the approaches and alternatives detailed in the outreach packet. (EPA also met with SERs on November 13, 2008 for an initial outreach meeting.) The Panel received written comments from the SERs following the meeting in response to discussions at the meeting and the questions posed to the SERs by the Agency. The SERs were specifically asked to provide comment on regulatory alternatives that could help to minimize the rule's impact on small businesses.

(2) Panel Recommendations for Small Business Flexibilities

The Panel recommended that EPA consider and seek comment on a wide range of regulatory alternatives to mitigate the impacts of the rulemaking on small businesses, including those flexibility options described below. The following section summarizes the SBAR Panel recommendations. EPA has proposed provisions consistent with each of the Panel's recommendations regarding area source facilities.

Consistent with the RFA/SBREFA requirements, the Panel evaluated the assembled materials and small-entity comments on issues related to elements of the IRFA. A copy of the Final Panel Report (including all comments received from SERs in response to the Panel's outreach meeting as well as summaries of both outreach meetings that were held with the SERs is included in the docket for this proposed rule. A summary of the Panel recommendations is detailed below. As noted above, this proposal includes proposed provisions for each of the Panel recommendations regarding area source facilities.

(a) Work Practice Standards

The panel recommended that EPA consider requiring annual tune-ups, including standardized criteria outlining proper tune-up methods targeted at smaller boiler operators. The panel further recommended that EPA take comment on the efficacy of energy assessments/audits at improving combustion efficiency and the cost of performing the assessments, especially to smaller boiler operators.

A work practice standard, instead of MACT emission limits, may be proposed if it can be justified under CAA section 112(h), that is, it is impracticable to enforce the emission standards due to technical and economic limitations. Work practice standards could reduce fuel use and improve combustion efficiency which would result in reduced emissions.

In general, SERs commented that a regulatory approach to improve combustion efficiency, such as work practice standards, would have positive impacts with respect to the environment and energy use and save on compliance costs. The SERs were concerned with work practice standards that would require energy assessments and implementation of assessment findings. The basis of these concerns rested upon the uncertainty that there is no guarantee that there are available funds to implement a particular assessment's findings.

(b) Subcategorization

The Panel recommended that EPA allow subcategorizations suggested by the SERs, unless EPA finds that a subcategorization is inconsistent with the Clean Air Act.

SERs commented that subcategorization is a key concept that could ensure that like boilers are compared with similar boilers so that MACT floors are more reasonable and could be achieved by all units within a subcategory using appropriate emission reduction strategies. SERs commented that EPA should subcategorize based on fuel type, boiler type, duty cycle, and location.

(c) Compliance Costs

The Panel recommended that EPA carefully weigh the potential burden of compliance requirements and consider for small entities options such as, emission averaging within facility, reduced monitoring/testing requirements, or allowing more time for compliance.

SERs noted that recordkeeping activities, as written in the vacated boiler MACT, would be especially challenging for small entities that do not have a dedicated environmental affairs department.

D. Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, we generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating a rule for which a written statement is needed, section 205 of the UMRA generally requires us to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows us to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before we establish any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, we must develop a small government agency plan under section 203 of the UMRA. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We have determined that this proposed rule contains a Federal mandate that may result in expenditures of $100 million or more for State, local, and Tribal governments, in the aggregate, or the private sector in any 1 year. Accordingly, we have prepared a written statement entitled "Unfunded Mandates Reform Act Analysis for the Proposed Industrial Boilers and Process Heaters NESHAP" under section 202 of the UMRA which is summarized below.

1. Statutory Authority

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

Section 112(d) of the CAA requires us to establish NESHAP for both major and area sources of HAP that are listed for regulation under CAA section 112(c). CAA section 112(k)(3)(B) calls for EPA to identify at least 30 HAP which, as the result of emissions from area sources, pose the greatest threat to public health in the largest number of urban areas. CAA section 112(c)(3) requires 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), we may elect to promulgate standards or requirements for area sources based on GACT used by those sources to reduce emissions of HAP. Determining what constitutes GACT involves considering the control technologies and management practices that are generally available to the area sources in the source category. We also consider the standards applicable to major sources in the analogous source category and, as appropriate, the control technologies and management practices at area and major sources in similar categories, to determine if the standards, technologies, and/or practices are transferable and generally available to area sources. In determining GACT for a particular area source category, we consider the costs and economic impacts of available control technologies and management practices on that category.

While GACT may be a basis for standards for most types of HAP emitted from area source, CAA section 112(c)(6) requires that source categories accounting for emissions of the HAP listed in CAA section 112(c)(6) be subject to standards under CAA section 112(d)(2) for the listed pollutants. Thus, CAA section 112(c)(6) requires that emissions of each listed HAP for the listed categories be subject to MACT regulation. The CAA section 112(c)(6) list of source categories includes industrial boilers and institutional/commercial boilers. Within these two source categories, coal combustion, oil combustion, and wood combustion have been on the CAA section 112(c)(6) list because of emissions of mercury and POM. We currently believe that regulation of coal-fired boilers will ensure that we fulfill our obligation under CAA section 112(c)(6) with respect to mercury reductions. Consequently, we deem it reasonable to propose to regulate the coal-fired boilers under MACT, rather than the biomass and oil-fired boilers, to obtain additional mercury reductions towards achieving the CAA section 112(c)(6) obligation. We propose to regulate biomass-fired and oil-fired boilers under GACT.

This proposed NESHAP would apply to all existing and new industrial boilers, institutional boilers, and commercial boilers located at area sources. In compliance with section 205(a) of the UMRA, we identified and considered a reasonable number of regulatory alternatives. Additional information on the costs and environmental impacts of these regulatory alternatives is presented in the docket.

The regulatory alternative upon which the proposed standards are based represents the MACT floor for the listed CAA section 112(c)(6) pollutants (mercury and POM) and GACT for the other urban HAP which formed the basis for the listing of these two area source categories. The proposed standards would require new coal-fired boilers to meet MACT-based emission limits for mercury and CO (as a surrogate for POM) and GACT-based emission limits for PM (as a surrogate for urban metals). New biomass and oil-fired boilers would be required to meet MACT-based CO emission limits and GACT-based emission limits for PM. The emission limits for existing area source boilers are only applicable to area source boilers that have a designed heat input capacity of 10 MMBtu/h or greater. Existing large coal-fired boilers would be required to meet MACT-based emission limits for mercury and CO, and existing large biomass and oil-fired boilers would be subject to MACT-based CO emission limits. As allowed under CAA section 112(h), a work practice standard requiring the implementation of a tune-up program is being proposed for existing area source boilers with a designed heat input capacity of less than 10 MMBtu/h. An additional "beyond-the-floor" standard is being proposed for existing area source facilities having an affected boiler with a heat input capacity of 10 MMBtu/h or greater that requires the performance of an energy assessment on the boiler and the facility to identify cost-effective energy conservation measures.

2. Social Costs and Benefits

The regulatory impact analysis prepared for the proposed rule including the Agency's assessment of costs and benefits, is detailed in the "Regulatory Impact Analysis for the Proposed Industrial Boilers and Process Heaters MACT" in the docket. Based on estimated compliance costs associated with the proposed rule and the predicted change in prices and production in the affected industries, the estimated social costs of the proposed rule are $0.5 billion (2008 dollars).

It is estimated that 3 years after implementation of the proposed rule, HAP would be reduced by hundreds of tons, including reductions in metallic HAP including mercury, hydrochloric acid, hydrogen fluoride, and several other organic HAP from area source boilers. Studies have determined a relationship between exposure to these HAP and the onset of cancer, however, the Agency is unable to provide a monetized estimate of the HAP benefits at this time. In addition, there are reductions in $PM_{2.5}$ and in SO_2 that would occur, including 2,700 tons of $PM_{2.5}$ and 1,500 tons of SO_2. These reductions occur within 3 years after the implementation of the proposed regulation and are expected to continue throughout the life of the affected sources. The major health effect associated with reducing $PM_{2.5}$ and $PM_{2.5}$ precursors (such as SO_2) is a reduction in premature mortality. Other health effects associated with $PM_{2.5}$ emission reductions include avoiding cases of chronic bronchitis, heart attacks, asthma attacks, and work-lost days (*i.e.,* days when employees are unable to work). While we are unable to monetize the benefits associated with the HAP emissions reductions, we are able to monetize the benefits associated with the $PM_{2.5}$ and SO_2 emissions reductions. For SO_2 and $PM_{2.5}$, we estimated the benefits associated with health effects of PM but were unable to quantify all categories of benefits (particularly those associated with ecosystem and visibility effects). Our estimates of the monetized benefits in 2013 associated with the implementation of the proposed alternative range from $1.0 billion (2008 dollars) to $2.4 billion (2008 dollars) when using a 3 percent discount rate (or from $0.9 billion (2008 dollars) to $2.2 billion (2008 dollars) when using a 7 percent discount rate. The general approach used to value benefits is discussed in more detail earlier in this preamble. For more detailed information on the benefits estimated for the proposed rulemaking, refer to the RIA in the docket.

3. Future and Disproportionate Costs

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

We do not believe that there will be any disproportionate budgetary effects of the proposed rule on any particular areas of the country, State or local governments, types of communities (*e.g.,* urban, rural), or particular industry segments. See the results of the "Economic Impact Analysis of the Proposed Industrial Boilers and Process Heaters NESHAP," the results of which are discussed previously in this preamble.

4. Effects on the National Economy

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

The nationwide economic impact of the proposed rule is presented in the "Economic Impact Analysis for the Industrial Boilers and Process Heaters MACT" in the docket. This analysis provides estimates of the effect of the proposed rule on some of the categories mentioned above. The results of the economic impact analysis are summarized previously in this preamble. The results show that there will be a small impact on prices and output (less than 0.01 percent). In addition, there should be little impact on energy markets (in this case, coal, natural gas, petroleum products, and electricity). Hence, the potential impacts on the categories mentioned above should be small.

5. Consultation With Government Officials

The Unfunded Mandates Reform Act requires that we describe the extent of the Agency's prior consultation with affected State, local, and tribal officials, summarize the officials' comments or concerns, and summarize our response to those comments or concerns. In addition, section 203 of the UMRA requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a proposal. Consistent with the intergovernmental consultation provisions of section 204 of the UMRA, EPA has initiated consultations with governmental entities affected by this proposed rule. EPA invited the following 10 national organizations representing State and local elected officials to a meeting held on March 24, 2010 in Washington DC: (1) National Governors Association; (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations of elected State and local officials have been identified by EPA as the "Big 10" organizations appropriate to contact for purpose of consultation with elected officials. The purposes of the consultation were to provide general background on the proposal, answer questions, and solicit input from State/local governments. During the meeting, officials expressed uncertainty with regard to how boilers owned/operated by State and local entities would be impacted, as well as with regard to the potential burden associated with implementing the rule on State and local entities. To that end, officials requested and EPA provided (1) model boiler costs, (2) inventory of area source boilers (coal, oil, biomass only) for the 13 States for which we have an inventory, and (3) information on potential size of boilers used for various facility types and sizes. EPA has not received additional questions or requests from State or local officials.

Consistent with section 205, EPA has identified and considered a reasonable number of regulatory alternatives. Because an initial screening analysis for impact on small entities indicated a likely significant impact for substantial numbers EPA convened a SBAR Panel to obtain advice and recommendation of representatives of the small entities that potentially would be subject to the requirements of the rule. As part of that process, EPA considered several options. Those options included establishing emission limits, establishing work practice standards, and establishing work practice standards and requiring an energy assessment. The regulatory alternative selected is a combination of the options considered and includes proposed provisions regarding each of the SBAR Panel's recommendations for area source boilers. The recommendations regard subcategorization, work practice standards, and compliance costs (see section VIII.C. of this preamble for more detail).

EPA determined subcategorization based on boiler type to be appropriate because different types of units have different emission characteristics which may affect the feasibility and effectiveness of emission control. Thus, the proposal identifies three subcategories of area source boilers: (1) Boilers designed for coal firing, (2) boilers designed for biomass firing, and (3) boilers designed for oil firing.

The regulatory alternative upon which the proposed standards are based represents the MACT floor for mercury for coal-fired boilers, the MACT floor for POM (CO is used as a surrogate for POM) for coal, biomass, and oil-fired boilers, and GACT for the other urban HAP (PM is used as a surrogate for urban HAP metals and CO is used as a surrogate for urban organic pollutants) for coal, biomass, and oil-fired boilers. The emission limits for existing area source boilers are only applicable to area source boilers that have a designed heat input capacity of 10 MMBtu/h or greater. A work practice standard (for mercury from coal-fired boilers and for POM from all boilers) or management practice (for all other HAP, including mercury from biomass-fired and oil-fired boilers) requiring the implementation of a tune-up program is being proposed for existing area source boilers with a designed heat input capacity of less than 10 MMBtu/h. An additional "beyond-the-floor" standard is being proposed for existing area source facilities having an affected boiler with a heat input capacity of 10 MMBtu/h or greater that requires the performance of an energy assessment on the boiler and the facility to identify cost-effective energy conservation measures.

The proposed use of surrogate pollutants would result in reduced compliance costs because testing would only be required for the surrogate pollutants (*i.e.,* CO and PM) versus for the HAP (*i.e.,* POM and metals). The proposed work practice standard/management practice also would result in reduced compliance costs with respect to monitoring/testing for the smaller existing area source boilers. EPA's proposed exemption of most area source facilities from title V permit requirements also would reduce burden on area source boiler facilities.

This proposed rule is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. While some small governments may have boilers that would be affected by the proposed rule, EPA's analysis shows that other public facilities that are located at area source facilities owned by small entities would have cost-to-revenue ratios exceeding 10 percent. Hospitals' and schools' revenue tests fall below 1 percent. Because the proposed rule's requirements apply equally to boilers owned and/or operated by governments and to boilers owned and/or operated by private entities, there would be no requirements that uniquely apply to such governments or impose any disproportionate impacts on them.

E. Executive Order 13132: Federalism

Under Executive Order 13132, EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with State and local officials early in the process of developing the proposed action.

EPA has concluded that this action may have federalism implications, because it may impose substantial direct compliance costs on State or local governments, and the Federal government will not provide the funds necessary to pay those costs. Accordingly, EPA provides the following federalism summary impact statement as required by section 6(b) of Executive Order 13132.

Based on the estimates in EPA's RIA for today's action, the proposed regulatory option, if promulgated, may have federalism implications because the option may impose approximately $416 million in annual direct compliance costs on an estimated 57,000 State or local governments. Boiler inventories for the health services, educational services, and government-owned buildings sectors from 13 States were used to estimate the nationwide number of potentially impacted State or local governments. Because the inventories for these sectors include privately owned and Federal government owned facilities, the estimate may include many facilities that are not State or local government owned. Table 7 of this preamble presents estimates of the number of potentially impacted State and local governments and their potential annual compliance costs for each of the three sectors. In addition to an estimate of the total number of potentially impacted facilities, estimates for facilities with small boilers and for facilities with large boilers are presented. Small boilers (boilers with heat input capacity of less than 10 MMBtu/h) would be subject to a work practice standard that requires a boiler tune-up every 2 years. Large coal-fired boilers (boilers with heat input capacity of 10 MMBtu/h or greater) would be subject to emission limits for mercury and CO, while large biomass and oil-fired boilers would be subject to emission limits for CO. All facilities with large boilers would be required to conduct a one-time energy assessment.

TABLE 7—STATE AND LOCAL GOVERNMENTS POTENTIALLY IMPACTED BY THE PROPOSED STANDARDS FOR BOILERS AT AREA SOURCE FACILITIES

Sector	Number of potentially impacted facilities			Annual compliance costs to meet standards
	Total	Small	Large	
Health Services	17,206	15,293	1,913	$143 million.
Educational Services	34,052	33,303	749	$200 million.
Government-Owned Buildings	5,796	5,098	698	$73 million.
Total	57,054	53,694	3,360	$416 million.

EPA consulted with State and local officials in the process of developing the proposed action to permit them to have meaningful and timely input into its development. EPA met with 10 national organizations representing State and local elected officials to provide general background on the proposal, answer questions, and solicit input from State/local governments. The UMRA discussion in this preamble includes a description of the consultation.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed action from State and local officials.

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

Executive Order 13175 (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." The proposed rule does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. The proposed rule imposes requirements on owners and operators of specified area sources and not tribal governments. We do not know of any industrial, commercial, or institutional boilers owned or operated by Indian tribal governments. However, if there are any, the effect of the proposed rule on communities of tribal governments would not be unique or disproportionate to the effect on other communities. Thus, Executive Order 13175 does not apply to the proposed rule. EPA specifically solicits additional comment on the proposed rule from tribal officials.

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

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be "economically significant" as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

The proposed rule is not subject to Executive Order 13045 because the Agency does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. The reason for this determination is that the proposed rule is based solely on technology performance.

The public is invited to submit comments or identify peer-reviewed studies and data that assess effects of early life exposure to the proposed rule.

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

Executive Order 13211, (66 FR 28355, May 22, 2001), provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as significant energy actions. Section 4(b) of Executive Order 13211 defines "significant energy actions" as "any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) That is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action." The proposed rule is not a "significant regulatory action" because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The basis for the determination is as follows.

We estimate no significant changes for the energy sector for price, production, or imports. For more information on the estimated energy effects, please refer to the economic impact analysis for the proposed rule. The analysis is available in the public docket.

Therefore, we conclude that the proposed rule when implemented is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113, Section 12(d), 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in its regulatory activities, unless to do so would be inconsistent with applicable law or otherwise impractical. The VCS are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency does not use available and applicable VCS.

The proposed rule involves technical standards. The EPA cites the following standards in the proposed rule: EPA Methods 1, 2, 2F, 2G, 3A, 3B, 4, 5, 5D, 10, 10A, 10B, 17, 19, 29 of 40 CFR part 60; 101A of 40 CFR part 61; and voluntary consensus standards: American Society for Testing and Materials (ASTM) D6522–00, American Society of Mechanical Engineers (ASME) PTC 19 (manual methods only), ASTM D6784–02, ASTM D2234–D2234M–03, ASTM D6323–98, ASTM D2013–04, ASTM d5198–92, ASTM D5865–04, ASTM E711–87, ASTM D3173–03, ASTM E871–82, and ASTM D6722–01.

Consistent with the NTTAA, EPA conducted searches to identify voluntary consensus standards in addition to these EPA methods. No applicable voluntary consensus standards were identified for EPA Methods 2F, 2G, 5D, and 19. The search and review results are in the docket for this rule.

The search for emissions measurement procedures identified 16 other voluntary consensus standards. The EPA determined that these 16 standards identified for measuring emissions of the HAP or surrogates subject to emission standards in this rule were impractical alternatives to EPA test methods for the purposes of this rule. Therefore, EPA does not intend to adopt these standards for this purpose. The reasons for the determinations for the 16 methods can be found in the docket to this rule.

Table 4 to subpart JJJJJJ of this proposed rule lists the testing methods included in the regulation. Under section 3.7(f) and section 63.8(f) of Subpart A of the General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any required testing methods, performance specifications, or procedures.

EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable voluntary consensus standards and to explain why such standards should be used in this regulation.

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 (EJ). Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make EJ 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, low-income, and Tribal populations in the United States.

This proposed action establishes national emission standards for industrial, commercial, and institutional boilers that are area sources. The industrial boiler source category includes boilers used in manufacturing, processing, mining, refining, or any other industry. The commercial boiler source category includes boilers used in commercial establishments such as stores/malls, laundries, apartments, restaurants, theaters, and hotels/motels. The institutional boiler source category includes boilers used in medical centers (*e.g.,* hospitals, clinics, nursing homes), educational and religious facilities (*e.g.,* schools, universities, places of worship), and municipal buildings (*e.g.,* courthouses, arts centers, prisons). There are approximately 91,000 facilities affected by the proposed rule, most of which are small entities. By the defined nature of the category, many of these sources are located in close proximity to residential areas, commercial centers, and other locations where large numbers of people live and work.

Due to the large number of these sources, their nation-wide dispersal, and the absence of site specific coordinates, EPA is unable to examine the distributions of exposures and health risks attributable to these sources among different socio-demographic groups for this rule, or to relate the locations of expected emission reductions to the locations of current poor air quality. However, the rule is anticipated to have substantial emissions reductions of toxic air pollutants (*See* Table 2.), some of which are potential carcinogens, neurotoxins, and respiratory irritants. The rule will also result in substantial reductions in criteria pollutants such as CO, PM, SO_2, as well as ozone precursors.

Because of the close proximity of these source categories to people, the substantial emission reductions of air toxics resulting from the implementation of this proposed rule is anticipated to have health benefits for all persons living or going near these types of sources. (Please refer to the RIA for this rulemaking, which is available in the docket.) For example, there will be significant reductions of mercury emissions which will reduce potential exposures due to the atmospheric deposition of mercury for populations such as subsistence fisherman. In addition, there will be substantial reductions in other air toxics that can cause adverse health effects such as ozone precursors which contribute to "smog." This rule will not cause an increase in any adverse human health or environmental effects on any population, including any minority, low-income, or Tribal populations.

EPA defines "Environmental Justice" to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and polices. To promote meaningful involvement, EPA has developed an EJ communication strategy to ensure that interested communities have access to this proposed rule, are aware of its content, and have an opportunity to comment. During the comment period, EPA will publicize the rulemaking via EJ newsletters, Tribal newsletters, EJ listserves, and the Internet, including Office of Policy, Economics, and Innovation's (OPEI) Rulemaking Gateway Web site (*http://yosemite.epa.gov/opei/rulegate.nsf/content/index.html?opendocument*). EPA will also provide general rulemaking fact sheets (*e.g.,* why is this important for my community) for EJ community groups and conduct conference calls with interested communities. In addition, State and Federal permitting requirements will provide State, local governments and communities the opportunity to provide their comments on the permit conditions associated with permitting these sources.

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: April 29, 2010.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is proposed to be 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 revising paragraphs (b)(27), (b)(39), (b)(47), (b)(49), (b)(50), (b)(52), (b)(55), (b)(56), (b)(58), (b)(61), (b)(62), and (i)(1) to read as follows:

63.14 Incorporation by reference.

* * * * *

(b) * * *

(27) ASTM D 6522–00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers,[1] IBR approved for § 63.9307(c)(2), Table 4 to subpart ZZZZ, Table 5 to subpart DDDDD, and Table 4 to subpart JJJJJJ of this part.

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(39) ASTM Method D388–99 $^{\varepsilon 1}$, Standard Classification of Coals by Rank[1], IBR approved for § 63.7575 and § 63.11237.

* * * * *

(47) ASTM D5198–92 (Reapproved 2003), Standard Practice for Nitric Acid Digestion of Solid Waste,[1] IBR approved for Table 6 to subpart DDDDD and Table 5 to subpart JJJJJJ of this part.

* * * * *

(49) ASTM D6323–98 (Reapproved 2003), Standard Guide for Laboratory Subsampling of Media Related to Waste Management Activities,[1] IBR approved for Table 6 to subpart DDDDD and Table 5 to subpart JJJJJJ of this part.

(50) ASTM E711–87 (Reapproved 1996), Standard Test Method for Gross Calorific Value of Refuse-Derived Fuel by the Bomb Calorimeter,[1] IBR approved for Table 6 to subpart DDDDD and Table 5 to subpart JJJJJJ of this part.

* * * * *

(52) ASTM E871–82 (Reapproved 1998), Standard Method of Moisture Analysis of Particulate Wood Fuels,[1] IBR approved for Table 6 to subpart DDDDD and Table 5 to subpart JJJJJJ of this part.

* * * * *

(55) ASTM D2013–04, Standard Practice for Preparing Coal Samples for Analysis, IBR approved for Table 6 to subpart DDDDD and Table 5 to subpart JJJJJJ of this part.

(56) ASTM D2234–D2234M–03 $^{\varepsilon 1}$, Standard Practice for Collection of a Gross Sample of Coal, IBR approved for Table 6 to subpart DDDDD and Table 5 to subpart JJJJJJ of this part.

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(58) ASTM D3173–03, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved

for Table 6 to subpart DDDDD and Table 5 to subpart JJJJJJ of this part.

(61) ASTM D6722–01, Standard Test Method for Total Mercury in Coal and Coal Combustion Residues by the Direct Combustion Analysis, IBR approved for Table 6 to subpart DDDDD and Table 5 to subpart JJJJJJ of this part.

(62) ASTM D5865–04, Standard Test Method for Gross Calorific Value of Coal and Coke, IBR approved for Table 6 to subpart DDDDD and Table 5 to subpart JJJJJJ of this part.

* * * * *

(i) * * *

(1) ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus]," IBR approved for §§ 63.865(b), 63.3166(a), 63.3360(e)(1)(iii), 63.3545(a)(3), 63.3555(a)(3), 63.4166(a)(3), 63.4362(a)(3), 63.4766(a)(3), 63.4965(a)(3), 63.5160(d)(1)(iii), 63.9307(c)(2), 63.9323(a)(3), Table 5 to subpart DDDDD, and Table 4 to subpart JJJJJJ of this part.

* * * * *

3. Add subpart JJJJJJ to read as follows:

Subpart JJJJJJ—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

Sec.

What This Subpart Covers

Emission Limits, Work Practice Standards, Emission Reduction Measures, and Management Practices

Initial Compliance Requirements

Continuous Compliance Requirements

Other Requirements and Information

Subpart JJJJJJ—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

What This Subpart Covers

§ 63.11193 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler as defined in § 63.11237 that is located at, or is part of, an area source of hazardous air pollutants (HAP), as defined in § 63.2.

§ 63.11194 What is the affected source of this subpart?

(a) This subpart applies to each new or existing affected sources as defined in paragraphs (a)(1) and (2) of this section.

(1) The affected source is the collection of all existing industrial, commercial, and institutional boilers within a subcategory located at an area source.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler located at an area source.

(b) An affected source is an existing source if you commenced construction or reconstruction of the affected source on or before June 4, 2010.

(c) An affected source is a new source if you commenced construction or reconstruction of the affected source after June 4, 2010.

(d) A boiler is a new affected source if you commenced fuel switching from natural gas to coal, biomass, or oil after June 4, 2010.

(e) Any source that was a major source and installed a control device on a boiler after November 15, 1990, and, as a result, became an area source under 40 CFR part 63 is required to obtain a permit under 40 CFR part 70 or 40 CFR part 71. Otherwise, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

§ 63.11195 Are any boilers not subject to this subpart?

The types of boilers listed in paragraphs (a) through (e) of this section are not subject to this subpart.

(a) Any boiler specifically listed as an affected source in another standard(s) under this part.

(b) Any boiler specifically listed as an affected source in another standard(s) established under section 129 of the Clean Air Act (CAA).

(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).

(d) A boiler that is used specifically for research and development. This does not include boilers that only provide steam to a process or for heating at a research and development facility.

(e) A gas-fired boiler as defined in this subpart.

§ 63.11196 What are my compliance dates?

(a) If you own or operate an existing affected source, you must achieve compliance with the applicable provisions in this subpart no later than [DATE 3 YEARS AFTER PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER].

(b) If you start up a new affected source on or before [DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER], you must achieve compliance with the provisions of this subpart no later than [DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER].

(c) If you start up a new affected source after [DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER], you must achieve compliance with the provisions of this subpart upon startup of your affected source.

Emission Limits, Work Practice Standards, Emission Reduction Measures, and Management Practices

§ 63.11200 What are the subcategories of boilers?

The subcategories of boilers are coal, biomass, and oil. Each subcategory is defined in § 63.11237.

§ 63.11201 What standards must I meet?

(a) You must comply with each emission limit specified in Table 1 of this subpart that applies to your boiler.

(b) You must comply with each work practice standard, emission reduction measure, and management practice specified in Table 2 of this subpart that applies to your boiler.

(c) These standards apply at all times.

Initial Compliance Requirements

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

(a) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) You can demonstrate compliance with any applicable mercury emission limit using fuel analysis if the emission rate calculated according to § 63.11211(b) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using stack testing.

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

(a) You must demonstrate initial compliance with each emission limit specified in Table 1 of this subpart that applies to you by either conducting performance (stack) tests, as applicable, according to § 63.11212 and Table 4 of this subpart or conducting fuel analyses, as applicable, according to § 63.11213 and Table 5 to this subpart.

(b) For affected sources that have an applicable carbon monoxide (CO) emission limit, your initial compliance requirements depend on the rated capacity of your boiler. If your boiler has a heat input capacity between 10 and 100 million British thermal units (MMBtu) per hour, your initial compliance demonstration is conducting a performance test for CO according to Table 4 to this subpart. If your boiler has a heat input capacity of 100 MMBtu per hour or greater, your initial compliance demonstration is conducting a performance evaluation of your continuous emission monitoring system (CEMS) for CO according to § 63.11223.

(c) For existing affected sources that have applicable emission limits, you must demonstrate initial compliance 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).

(d) For existing affected sources that have applicable work practice standards 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).

(e) For new affected sources, you must demonstrate initial compliance no later than 180 calendar days after [INSERT THE DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER] or within 180 calendar days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

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

(a) For affected sources that elect to 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 and conducting CMS performance evaluations according to § 63.11223.

(b) If you elect to demonstrate compliance with an applicable mercury emission limit through fuel analysis, you must conduct fuel analyses according to § 63.11213 and follow the procedures in paragraphs (b)(1) through (3) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler that would result in the maximum emission rates of mercury that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel mercury concentration of the composite samples analyzed for each fuel type using Equation 1 of this section.

$$P_{90} = \text{mean} + (SD * t) \qquad \text{(Eq. 1)}$$

Where:

P_{90} = 90th percentile confidence level mercury concentration, in pounds per million Btu;

mean = Arithmetic average of the fuel mercury concentration in the fuel samples analyzed according to § 63.11213, in units of pounds per million Btu;

SD = Standard deviation of the mercury concentration in the fuel samples analyzed according to § 63.11213, in units of pounds per million Btu;

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

(3) To demonstrate compliance with the applicable mercury emission limit, the emission rate that you calculate for your boiler using Equation 1 of this section must be less than the applicable mercury emission limit.

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

(a) You must conduct all performance tests according to the requirements in § 63.7.

(b) You must conduct each stack test according to the requirements in Table 4 to this subpart.

(c) You must conduct stack tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that have the highest content of mercury, and you must demonstrate initial compliance based on these tests.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). The sampling time for each test run must last at least 1 hour except that the sampling time for the test runs conducted for mercury emissions must last at least 2 hours.

(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 to part 60 of this chapter to convert the measured particulate matter concentrations and the measured mercury concentrations that result from the initial performance test to pounds per million Btu heat input emission rates.

§ 63.11213 What fuel analyses and procedures must I use for the performance tests?

(a) You must conduct fuel analyses according to the procedures in paragraphs (b) and (c) of this section and Table 5 to this subpart, as applicable.

(b) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in Table 5 of this subpart. Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during a test run period.

(c) Determine the concentration of mercury in the fuel in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 5 to this subpart.

§ 63.11214 When must I conduct subsequent performance tests?

(a) You must conduct all applicable performance (stack) tests according to § 63.11212 on an annual basis, unless you follow the requirements listed in paragraphs (b) through (d) of this section. Annual performance tests must be completed between 10 and 12 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (d) of this section.

(b) You can conduct performance stack tests less often for particulate matter or mercury if your performance stack tests for the pollutant for at least 3 consecutive years show that your emissions are at or below 75 percent of the emission limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions. In this case, you do not have to conduct a performance test for that pollutant for the next 2 years. You must conduct a performance test during the third year and no more than 36 months after the previous performance test.

(c) If your boiler continues to meet the emission limit for particulate matter or mercury, you may choose to conduct performance stack tests for the pollutant every third year if your emissions are at or below 75 percent of the emission limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions, but each such performance test must be conducted no more than 36 months after the previous performance test.

(d) If a performance test shows emissions exceeded 75 percent of the emission limit, you must conduct annual performance tests for that pollutant until all performance tests over consecutive 3-year period show compliance.

(e) If you have an applicable CO emission limit and your boiler has a heat input capacity between 10 and 100 MMBtu per hour, you must conduct annual performance tests for CO according to § 63.11211. Each annual performance test must be conducted between 10 and 12 months after the previous performance test.

(f) If you demonstrate compliance with the mercury based on fuel analysis, you must conduct a fuel analysis according to § 63.11213 for each type of fuel burned monthly. 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.

§ 63.11215 How do I demonstrate initial compliance with the work practice standard, emission reduction measures, and management practice?

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

(b) 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 the energy assessment report, along with a signed certification that the assessment is an accurate depiction of your facility.

Continuous Compliance Requirements

§ 63.11220 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.11223.

(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, or required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

§ 63.11221 How do I demonstrate continuous compliance with the emission limits?

(a) You must demonstrate continuous compliance with each emission limit and operating limit in Tables 1 and 3 to this subpart that applies to you according to paragraphs (a)(1) through (5) of this section.

(1) Following the date on which the initial performance test is completed or is required to be completed under §§ 63.7 and 63.11196, whichever date comes first, you must not operate above any of the applicable maximum operating limits or below any of the applicable minimum operating limits listed in Table 3 to this subpart at all times. Operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits. Operating limits are confirmed or reestablished during performance tests.

(2) If you have an applicable mercury emission limit, you must keep records of the type and amount of all fuels burned in each boiler during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in lower emissions of mercury than the applicable emission limit.

(3) If you have you have an applicable mercury emission limit and you plan to burn a new type of fuel, you must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis and meet the requirements in paragraphs (a)(3)(i) or (ii) of this section.

(i) The recalculated mercury emission rate must be less than the applicable emission limit.

(ii) If the results are higher than mercury fuel input during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.11212 to demonstrate that the mercury emissions do not exceed the emission limit.

(4) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alarm and operate and maintain the fabric filter system such that the alarm does not sound more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alarm, the time corrective action was initiated and completed, and a brief description of the

cause of the alarm and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time shall be counted as the actual amount of time taken to initiate corrective action.

(5) If you have an applicable CO emission limit and you are required to install a CEMS according to § 63.11223, then you must continuously monitor CO according to §§ 63.11223(a) and 63.11220 and maintain a CO emission level below your applicable CO emission limit in Table 1 to this subpart at all times.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 and 3 to this subpart that apply to you. These instances are deviations from the emission limits in this subpart. These deviations must be reported according to the requirements in § 63.11224.

§ 63.11222 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, you must keep records as required in § 63.11224(c) to demonstrate continuous compliance.

(b) You must conduct a tune-up of the boiler biennially to demonstrate continuous compliance as specified in paragraphs (b)(1) through (6) of this section.

(1) Inspect the burner, and clean or replace any components of the burner as necessary;

(2) Inspect the flame pattern and make any adjustments to the burner necessary to optimize the flame pattern consistent with the manufacturer's specifications;

(3) Inspect the system controlling the air-to-fuel ratio, and ensure that it is correctly calibrated and functioning properly;

(4) Minimize total emissions of CO consistent with the manufacturer's specifications;

(5) Measure the concentration in the effluent stream of CO in parts per million, by volume, dry basis (ppmvd), before and after the adjustments are made; and

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

(i) The concentrations of CO in the effluent stream in ppmvd, and oxygen in percent dry basis, measured before and after the adjustments of the boiler;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type and amount of fuel used over the 12 months prior to the annual adjustment.

§ 63.11223 What are my monitoring, installation, operation, and maintenance requirements?

(a) If you are using a control device to comply with the emission limits specified in Table 1 of this subpart, you must maintain each operating limit in Table 3 of this subpart that applies to your boiler. If you use a control device not covered in Table 3, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the United States Environmental Protection Agency (EPA) Administrator for approval of alternative monitoring under § 63.8(f).

(b) If you demonstrate compliance with any applicable emission limit through stack testing, you must develop a site-specific monitoring plan according to the requirements in paragraphs (b)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each continuous monitoring system (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 (b)(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.

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

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations).

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

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1), (3), and (4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

(c) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each continuous parameter monitoring system (CPMS) according to the procedures in paragraphs (c)(1) through (5) of this section.

(1) The CPMS must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data.

(2) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must conduct all monitoring in continuous operation at all times that the unit is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(3) For purposes of calculating data averages, you must not use data recorded during monitoring malfunctions, associated repairs, out of control periods, or required quality assurance or control activities. You must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(4) Determine the 3-hour block average of all recorded readings, except as provided in paragraph (c)(3) of this section.

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

(d) If you have an applicable opacity operating limit, you must install, operate, certify and maintain each continuous opacity monitoring system (COMS) according to the procedures in paragraphs (d)(1) through (7) of this section by the compliance date specified in § 63.11196.

(1) Each COMS must be installed, operated, and maintained according to PS 1 of 40 CFR part 60, appendix B.

(2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8 and according to PS 1 of 40 CFR part 60, appendix B.

(3) As specified in § 63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in § 63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in § 63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). 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 determine and record all the 1-hour block averages collected for periods during which the COMS is not out of control.

(e) If you have an applicable CO emission limit and your boiler has a heat input capacity of 100 MMBtu per hour or greater, you must install, operate, and maintain a CEMS for CO and oxygen according to the procedures in paragraphs (e)(1) through (6) of this section by the compliance date specified in § 63.11196. The CO and oxygen shall be monitored at the same location at the outlet of the boiler.

(1) Each CEMS must be installed, operated, and maintained according to Performance Specification (PS) 4A of 40 CFR part 60, appendix B, and according to the site-specific monitoring plan developed according to § 63.11223.

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

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2).

(5) You must calculate and record all daily averages. A new daily average emission rate is calculated as the average of all of the hourly CO emission data for the calendar day.

(6) For purposes of calculating data averages, you must not use data recorded during periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities, or when your boiler is operating at less than 50 percent of its rated capacity. You must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out of control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(f) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each CEMS according to the requirements in § 63.8(d).

§ 63.11224 What are my notification, reporting, and recordkeeping, requirements?

(a) You must submit the notifications specified in paragraphs (a)(1) through (a)(4) of this section.

(1) You must submit all of the notifications in §§ 63.5(b), 63.7(b): 63.8(e) and (f); 63.9(b) through (e); and 63.9(g) and (h) that apply to you by the dates specified in those sections.

(2) As specified in § 63.9(b)(2), you must submit the Initial Notification no later than 120 calendar days after [INSERT THE DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER] or within 120 days after the source becomes subject to the standard.

(3) You must submit the Notification of Compliance Status in accordance with § 63.9(h) no later than 120 days after the applicable compliance date specified in § 63.11196 unless you must conduct a performance test. If you must conduct a performance test, you must submit the Notification of Compliance Status within 60 days of completing the performance test. In addition to the information required in § 63.9(h)(2), 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 § 63.11222(b) to conduct a biennial tune-up of the boiler".

(ii) "This facility has had an energy assessment performed according to § 63.11215."

(iii) This certification of compliance by the owner or operator that installs bag leak detection systems: "This facility has prepared a bag leak detection system monitoring plan in accordance with § 63.11221 and will operate each bag leak detection system according to the plan."

(4) 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 consistent with § 63.7(e)(2)(iv), you must submit the test data in lieu of the initial performance test results with the Notification of Compliance Status required under paragraph (a)(3) of this section.

(b) You must prepare, by March 1 of each year, an annual compliance certification report for the previous calendar year containing the information specified in paragraphs (b)(1) through (b)(3) of this section. You must submit the report by March 15 if you had any instance described by paragraph (b)(3) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with the official's name, title, phone number, e-mail 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.

(3) If the source is not in compliance, include a description of deviations from the applicable requirements, the time periods during which the deviations occurred, and the corrective actions taken.

(4) The total fuel use by each affected source subject to an emission limit, for each calendar month within the reporting period, including, but not limited to, a description of the fuel, including whether the fuel has received a non-waste determination by you or EPA, and the total fuel usage amount with units of measure.

(c) You must maintain the records specified in paragraphs (c)(1) through (5) of this section.

(1) As required in § 63.10(b)(2)(xiv), you must keep a copy of each notification and report that you submitted to comply with this subpart and all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted.

(2) You must keep records to document conformance with the work practices, emission reduction measures, and management practices required by

§ 63.11215 as specified in paragraphs (c)(2)(i) through (iv) of this section.

(i) Records must identify each boiler, the date of tune-up, the procedures followed for tune-up, and the manufacturer's specifications to which the boiler was tuned.

(ii) Records documenting monthly fuel use by each boiler, including the type(s) of fuel, including, but not limited to, a description of the fuel, including whether the fuel has received a non-waste determination by you or EPA, and the total fuel usage amount with units of measure.

(3) For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation that were done to demonstrate compliance with the mercury emission limits. Supporting documentation should include results of any fuel analyses. You can use the results from one fuel analysis for multiple boilers provided they are all burning the same fuel type.

(4) You must keep the records of all inspection and monitoring data required by §§ 63.11221 and 63.11222, and the information identified in paragraphs (c)(4)(i) through (vi) of this section for each required inspection or monitoring.

(i) The date, place, and time of the monitoring event;

(ii) Person conducting the monitoring;

(iii) Technique or method used;

(iv) Operating conditions during the activity;

(v) Results, including the date, time, and duration of the period from the time the monitoring indicated a problem to the time that monitoring indicated proper operation; and

(vi) Maintenance or corrective action taken (if applicable).

(5) If you use a bag leak detection system, you must keep the records specified in paragraphs (c)(5)(i) through (iii) of this section.

(i) Records of the bag leak detection system output.

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings.

(iii) The date and time of all bag leak detection system alarms, and for each valid alarm, the time you initiated corrective action, the corrective action taken, and the date on which corrective action was completed.

(d) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1). As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each recorded action. You must keep each record onsite for at least 2 years after the date of each recorded action according to § 63.10(b)(1). You may keep the records offsite for the remaining 3 years.

(e) For affected facilities having applicable emission limits, you must submit an electronic copy of stack test reports to EPA's WebFIRE data base, the owner or operator of an affected facility shall enter the test data into EPA's data base using the Electronic Reporting Tool located at *http://www.epa.gov/ttn/chief/ert/ert_tool.html.*

Other Requirements and Information

§ 63.11235 What parts of the General Provisions apply to me?

Table 6 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.11236 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by EPA or a delegated authority 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.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraphs (c) of this section are retained by the EPA Administrator and are not transferred to the State, local, or tribal agency.

(c) The authorities that cannot be delegated to State, local, or tribal agencies are specified in paragraphs (c)(1) through (5) of this section.

(1) Approval of an alternative non-opacity emission standard and work practice standards in § 63.11223(a).

(2) Approval of alternative opacity emission standard under § 63.6(h)(9).

(3) Approval of major change to test methods under § 63.7(e)(2)(ii) and (f). A "major change to test method" is defined in § 63.90.

(4) Approval of a major change to monitoring under § 63.8(f). A "major change to monitoring" is defined in § 63.90.

(5) Approval of major change to recordkeeping and reporting under § 63.10(f). A "major change to recordkeeping/reporting" is defined in § 63.90.

§ 63.11237 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA, in § 63.2 (the General Provisions), and in this section as follows:

Bag leak detection system means an instrument that is 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.

Biomass means but is not limited to, wood residue, and wood products (*e.g.,* trees, tree stumps, tree limbs, bark, lumber, sawdust, sanderdust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (*e.g.,* almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass fuel is not intended to suggest that these materials are or not solid waste.

Biomass subcategory includes any boiler that burns any amount of biomass, but no coal, either alone or in combination with liquid fuels or gaseous fuels.

Boiler means an enclosed combustion device in which water is heated to recover thermal energy in the form of steam or hot water. A device combusting solid waste, as defined in 40 CFR 241.3, is not a boiler. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feedwater system, the combustion air system, the fuel system (including burners), blowdown system, combustion control system, and the energy consuming systems.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388–99e1, "Standard Specification for Classification of Coals by Rank[1]" (incorporated by reference, see § 63.14(b)) and synthetic fuels derived from coal including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

Coal subcategory includes any boiler that burns any coal alone or at least 10 percent coal on an annual heat input basis in combination with biomass, liquid fuels, or gaseous fuels.

Commercial boiler means a boiler used in commercial establishments such as hotels, restaurants, and laundries to provide electricity, steam, and/or hot water that does not combust solid waste, as that term is defined by the Administrator under RCRA.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) 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; or

(3) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

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 in fluidized bed boilers are included in this definition.

Electrostatic precipitator 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.

Energy assessment means an in-depth assessment of a facility to identify immediate and long-term opportunities to save energy, focusing on the steam and process heating systems which involves a thorough examination of potential savings from energy efficiency improvements, waste minimization and pollution prevention, and productivity improvement.

Equivalent means the following only as this term is used in Table 5 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining mercury using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing this metal. On the other hand, if metals analysis is done on an "as received" basis, a separate aliquot can be dried to determine moisture content and the mercury concentration mathematically adjusted to a dry basis.

(6) An equivalent mercury determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for mercury and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 5 to this subpart for the same purpose.

Fabric filter means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse.

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including the requirements of 40 CFR part 60 and 40 CFR part 61, 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.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, distillate oil, residual oil.

Gaseous fuels includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas.

Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, 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, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity that does not combust solid waste, as that term is defined by the Administrator under RCRA.

Institutional boiler means a boiler used in institutional establishments such as medical centers, research centers, and institutions of higher education to provide electricity, steam, and/or hot water that does not combust solid waste, as that term is defined by the Administrator under RCRA.

Liquid fuel means petroleum, distillate oil, residual oil, any form of liquid fuel derived from petroleum, on-spec used oil, and biodiesel.

Minimum sorbent flow rate means 90 percent of the test average sorbent (or activated carbon) flow rate measured according to Table 6 to this subpart during the most recent performance 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) Liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835–03a, "Standard Specification for Liquid Petroleum Gases" (incorporated by reference, see § 63.14(b)).

Oil subcategory includes any boiler that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels. Gas boilers that burn liquid fuel during periods of gas curtailment, gas supply emergencies, or for periodic testing of liquid fuel are not included in this definition.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

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

Performance testing means the collection of data resulting from the execution of a test method used (either by stack testing or fuel analysis) to demonstrate compliance with a relevant emission standard.

Period of natural gas curtailment or supply interruption means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption.

Qualified personnel mean specialists in evaluating energy systems, such as, those who have successfully completed the DOE Qualified Specialist program for all systems, Certified Energy Managers certified by the Association of Energy Engineers, or the equivalent.

Responsible official means responsible official as defined in 40 CFR 70.2.

Tune-up means adjustments made to a boiler in accordance with procedures supplied by the manufacturer (or an approved specialist) to optimize the combustion efficiency.

Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers, but are considered boilers. Waste heat boilers are also referred to as heat recovery steam generators.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the CAA.

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 meet the following emission limits . . .
1. New coal	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Mercury	0.000003 lb per MMBtu of heat input.
	c. Carbon Monoxide	310 ppm by volume on a dry basis corrected to 7 percent oxygen (daily average).
2. New biomass	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Carbon Monoxide	100 ppm by volume on a dry basis corrected to 7 percent oxygen (daily average).
3. New oil	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Carbon Monoxide	1 ppm by volume on a dry basis corrected to 3 percent oxygen (daily average).
4. Existing coal (units with heat input capacity of 10 million Btu per hour or greater).	a. Mercury	0.000003 lb per MMBtu of heat input.
	b. Carbon Monoxide	310 ppm by volume on a dry basis corrected to 7 percent oxygen (daily average).
5. Existing biomass (units with heat input capacity of 10 million Btu per hour or greater).	Carbon Monoxide	160 ppm by volume on a dry basis corrected to 7 percent oxygen (daily average).
6. Existing oil (units with heat input capacity of 10 million Btu per hour or greater).	Carbon Monoxide	2 ppm by volume on a dry basis corrected to 3 percent oxygen (daily average).

As stated in §§ 63.11202 and 63.11203, you must comply with the following applicable work practice standards:

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 coal, biomass, or oil (units with heat input capacity of less than 10 million Btu per hour).	a. Conduct a tune-up of the boiler biennially as specified in § 63.11222.
2. Existing coal, biomass, or oil (units with heat input capacity of 10 million Btu per hour and greater).	Must have an energy assessment performed by qualified personnel which includes: (1) a visual inspection of the boiler system. (2) establish operating characteristics of the facility, energy system specifications, operating and maintenance procedures, and unusual operating constraints, (3) identify major energy consuming systems, (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, (6) the energy savings potential of the energy conservation measures identified,

TABLE 2 TO SUBPART JJJJJJ 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 . . .
	(7) a comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

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

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

If you demonstrate compliance with applicable mercury emission limits using . . .	You must meet these operating limits . . .
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 § 63.11221 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	Maintain opacity to less than or equal to 10 percent opacity (daily block average).
3. Dry scrubber or carbon injection control	Maintain the minimum sorbent or carbon injection rate at or above the operating levels established during the performance test that demonstrated compliance with the applicable emission limit for mercury.
4. Fuel analysis	Maintain the fuel type or fuel mixture (annual average) such that the mercury emission rates calculated according to § 63.11211(c) is less than the applicable emission limits for mercury.

As stated in § 63.11212, you must comply with the following requirements for performance (stack) test for new affected sources:

TABLE 4 TO SUBPART JJJJJJ OF PART 63—PERFORMANCE (STACK) TESTING REQUIREMENTS

To conduct a performance test for the following pollutant . . .	You must . . .	Using . . .
1. Particulate Matter	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see § 63.14(b)), or ASME PTC 19, Part 10(1981) (IBR, see § 63.14(i)).
	d. Measure the moisture content of the stack gas	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb/MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
2. Mercury	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see § 63.14(b)), or ASME PTC 19, Part 10(1981)(IBR, see § 63.14(i)).
	d. Measure the moisture content of the stack gas	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the mercury emission concentration	Method 29 in appendix A to part 60 of this chapter or Method 101A in appendix B to part 61 of this chapter or ASTM Method D6784–02 (IBR, see § 63.14(b)).
	f. Convert emissions concentration to lb/MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
3. Carbon Monoxide	a. Select the sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.

TABLE 4 TO SUBPART JJJJJJ OF PART 63—PERFORMANCE (STACK) TESTING REQUIREMENTS—Continued

To conduct a performance test for the following pollutant . . .	You must . . .	Using . . .
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see § 63.14(b)), or ASME PTC 19, Part 10(1981)(IBR, see § 63.14(i)).
	d. Measure the moisture content of the stack gas	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the carbon monoxide emission concentration.	Method 10, 10A, or 10 B in appendix A to part 60 of this chapter or ASTM D6522–00 (IBR, see § 63.14(b).
	f. Convert emissions concentration to lb/MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.

As stated in § 63.11213, you must comply with the following requirements for fuel analysis testing for new affected sources:

TABLE 5 TO SUBPART JJJJJJ OF PART 63—FUEL ANALYSIS REQUIREMENTS

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.11213(c) or ASTM D2234–D2234M–03$^{\varepsilon 1}$ (for coal) (IBR, see § 63.14(b)) or ASTM D6323–98 (2003) (for biomass) (IBR, see § 63.14(b)) or equivalent.
	b. Compose fuel samples	Procedure in § 63.11213(c) or equivalent.
	c. Prepare composited fuel samples	SW–846–3050B (for solid samples) or SW–846–3020A (for liquid samples) or ASTM D2013–04 (for coal) (IBR, see § 63.14(b)) or ASTM D5198–92 (2003) (for biomass) (IBR, see § 63.14(b)) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865–04 (for coal) (IBR, see § 63.14(b)) or ASTM E711–87 (1996) (for biomass) (IBR, see § 63.14(b)) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173–03 (IBR, see § 63.14(b)) or ASTM E871–82 (1998) (IBR, see § 63.14(b)) or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722–01 (for coal) (IBR, see § 63.14(b)) or SW–846–7471A (for solid samples) or SW–846 7470A (for liquid samples) or equivalent.
	g. Convert concentrations into units of lb/MMBtu of heat content.	

As stated in § 63.11235, you must comply with the applicable General Provisions according to the following:

TABLE 6 TO SUBPART JJJJJJ OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART JJJJJJ

Citation	Subject	Applies to subpart JJJJJJ
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements.	No.
§ 63.6(a), (b)(1)–(b)(5), (b)(7), (c), (f)(2)–(3), (g), (i), (j).	Compliance with Standards and Maintenance Requirements.	Yes.
§ 63.6(e)(1), (e)(3), (f)(1), and (h)	Startup, shutdown, and malfunction requirements and Opacity/Visible Emission Limits.	No. Standards apply at all times, including during startup, shutdown, and malfunction events.
§ 63.7(a), (b), (c), (d), (e)(2)–(e)(9), (f), (g), and (h).	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Conditions for conducting performance tests	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.11210.
§ 63.8	Monitoring Requirements	Yes.

TABLE 6 TO SUBPART JJJJJJ OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART JJJJJJ—Continued

Citation	Subject	Applies to subpart JJJJJJ
§ 63.9	Notification Requirements	Yes. Subpart JJJJJJ requires submission of Notification of Compliance Status within 120 days of compliance date unless a performance test is required.
§ 63.10(a), (b)(1), (b)(2)(i)–(iii), (b)(2)(vi)–(xiv), (c)(1)–(c)(14), (d)(1)–(2), and (f).	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(iv)–(v), (b)(3), (d)(3)–(5), and (e)		No, Subpart JJJJJJ requires submission on an annual basis.
§ 63.10(c)(15)	Allows use of SSM plan	No.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13–63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.
§ 63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3)–(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)–(4), (c)(9).	Reserved	No.

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