ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2005–0031; FRL–8576–2]

RIN 2060–AO61

Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971; Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978; Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units; and Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to amend the new source performance standards for electric utility steam generating units and industrial-commercial-institutional steam generating units. On June 13, 2007, EPA promulgated amendments to the standards for steam generating units. Subsequently, EPA received a petition for reconsideration which it is granting to the extent specified in the proposed action. EPA is proposing to amend specific provisions in the standards for steam generating units, as amended, to resolve issues and questions raised by the petitioner for reconsideration, and to correct technical and editorial errors that have been identified since promulgation. In addition, EPA is requesting comment on the appropriate opacity standard for owners/operators of affected facilities using a particulate matter continuous emissions monitoring system to demonstrate compliance with the applicable PM limit.

DATES: *Comments.* Comments must be received on or before July 28, 2008. If anyone contacts EPA by June 23, 2008 requesting to speak at a public hearing, EPA will hold a public hearing on June 27, 2008.

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2005–0031, by one of the following methods:

- *http://www.regulations.gov.* Follow the on-line instructions for submitting comments.
- *E-mail: a-and-r-docket@epa.gov.*
- *By Facsimile:* (202) 566–1741.
- *Mail:* Air and Radiation Docket, U.S. EPA, Mail Code 6102T, 1200 Pennsylvania Ave., NW., Washington, DC 20460. 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, Office of Management and Budget (OMB), *Attn:* Desk Officer for EPA, 725 17th Street, NW., Washington, DC 20503. EPA requests a separate copy also be sent to the contact person identified below (see **FOR FURTHER INFORMATION CONTACT**).
- *Hand Delivery:* EPA Docket Center, Docket ID Number EPA–HQ–OAR–2005–0031, EPA West Building, 1301 Constitution Ave., NW., Room 3334, Washington, DC 20004. Such deliveries are accepted only during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2005–0031. EPA's policy is that all comments received will be included in the public docket 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 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 through *http://www.regulations.gov,* EPA recommends that you include your name and other contact information in the body of your comment as well as 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. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

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. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Air and Radiation Docket EPA/DC, EPA West, 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 and Radiation Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division (D243–01), U.S. EPA, Research Triangle Park, NC 27711, telephone number (919) 541–4003, facsimile number (919) 541–5450, electronic mail (e-mail) address: *fellner.christian@epa.gov.*

SUPPLEMENTARY INFORMATION:

Regulated Entities. Entities potentially affected by this proposed action include, but are not limited to, the following:

Category	NAICS [1]	Examples of regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal Government	22112	Fossil fuel-fired electric utility steam generating units owned by the Federal Government.
State/local/tribal government	22112	Fossil fuel-fired electric utility steam generating units owned by municipalities.
	921150	Fossil fuel-fired electric utility steam generating units located in Indian Country.

Category	NAICS[1]	Examples of regulated entities
Any industrial, commercial, or institutional facility using a steam generating unit as defined in 60.40b or 60.40c.	211	Extractors of crude petroleum and natural gas.
	321	Manufacturers of lumber and wood products.
	322	Pulp and paper mills.
	325	Chemical manufacturers.
	324	Petroleum refiners and manufacturers of coal products.
	316, 326, 339	Manufacturers of rubber and miscellaneous plastic products.
	331	Steel works, blast furnaces.
	332	Electroplating, plating, polishing, anodizing, and coloring.
	336	Manufacturers of motor vehicle parts and accessories.
	221	Electric, gas, and sanitary services.
	622	Health services.
	611	Educational Services.

[1] North American Industry Classification System (NAICS) code.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by the proposed rule. To determine whether your facility is regulated by the proposed rule, you should examine the applicability criteria in § 60.40a, § 60.40b, or § 60.40c of 40 CFR part 60. If you have any questions regarding the applicability of the proposed rule to a particular entity, contact the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

WorldWide Web (WWW). Following the Administrator's signature, a copy of the proposed amendments will be posted on the Technology Transfer Network's (TTN) policy and guidance page for newly proposed or promulgated rules at *http://www.epa.gov/ttn/oarpg.* The TTN provides information and technology exchange in various areas of air pollution control.

Public Hearing. If a public hearing is requested, it will be held at 10 a.m. at the EPA Facility Complex in Research Triangle Park, North Carolina or at an alternate site nearby. Contact Mr. Christian Fellner at 919–541–4003 to request a hearing, to request to speak at a hearing, to determine if a hearing will be held, or to determine the hearing location.

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

I. Background

New source performance standards (NSPS) implement Clean Air Act (CAA) section 111(b) and are issued for categories of sources which have been identified as causing, or contributing significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. The primary purpose of the NSPS are to help States attain and maintain ambient air quality by ensuring that the best demonstrated emission control technologies are installed as industrial infrastructure is modernized. Since 1970, the NSPS have been successful in achieving long-term emissions reductions in numerous industries by assuring cost-effective controls are installed on new, reconstructed, and modified sources.

CAA section 111 requires that NSPS reflect the degree of emission limitation achievable through application of the best system of emissions reductions which (taking into consideration the cost of achieving such emissions reductions, any non-air quality health and environmental impact, and energy requirements) the Administrator determines has been adequately demonstrated. This level of control is commonly referred to as best demonstrated technology (BDT). CAA section 111(b)(1)(B) requires the EPA to periodically review and revise the standards of performance, as necessary, to reflect improvements in methods for reducing emissions.

We promulgated amendments to the new source performance standards for steam generating units (40 CFR part 60, subparts D, Da, Db, and Dc) on June 13, 2007 (72 FR 32710). The amendments added compliance alternatives for owners and operators of certain affected sources, revised certain recordkeeping and reporting requirements, corrected technical and editorial errors, and updated the grammatical style of the four subparts to be more consistent across all four steam generating unit NSPS.

A petition for reconsideration of the amendments was filed by the Coke Oven Environmental Task Force (COETF), and we have decided to grant reconsideration of the amendments to the extent specified in the proposed rule. The amendments proposed by this action address specific issues for which the petitioners requested reconsideration.

As part of this action, we are also proposing to specify opacity monitoring requirements for owners/operators of affected facilities that are subject to an opacity limit, but are not required to use a continuous opacity monitor system (COMS). In addition, we are proposing to amend other rule language to correct technical omissions, typographical errors, cross-reference errors, grammatical errors, and various other issues that have been identified since promulgation of the previous amendments. The proposed amendments would not significantly change our original projections for the rule's compliance costs, environmental benefits, burden on industry, or the number of affected facilities.

II. Proposed Amendments

A. Opacity Monitoring

We are proposing multiple options to monitor opacity for owners/operators of affected facilities that are subject to an opacity limit, but exempt from the COMS requirement. Under the first option, the owner/operator conducts an annual EPA Method 9 opacity performance test on each affected facility to demonstrate compliance with the applicable opacity limit. A second option is for the owner/operator to use annual EPA Method 22 observations in lieu of Method 9 observations to demonstrate that the sum of occurrences of any visible emissions is not in excess of 5 percent of the observation period. As a third option, we are proposing the use of a digital photographic technique for detecting visible emissions, as an explicit alternative to Method 22 observations. This proposed rule references an EPA preliminary method entitled ''Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems'' found at *http://www.epa.gov/tnn/emc/prelim/pre-008.pdf.* For this third option, the facility owner/operator would prepare a site-specific monitoring plan based on this technology for approval. Observations using either Method 22 or the digital photographic technique demonstrating that the presence of visible emissions is less than 5 percent of the observation period would be sufficient to demonstrate compliance with the opacity limit. However, if either the Method 22 observation or the digital photographic technique shows the presence of visible emissions in excess of 5 percent of the observation period, then the owner/operator would be required to conduct a Method 9 performance test within 24 hours to demonstrate compliance with the opacity limit.

We are also proposing to require owners/operators of affected facilities that elect to use PM CEMS to measure both the filterable and condensable particulate matter emissions and to take Method 9 opacity readings during the initial PM CEMS calibration and ongoing correlation testing and to electronically report those results.

B. Additional Proposed Amendments to Subpart D

We are proposing to exempt owners/operators of affected facilities subject to subpart D that burn 500 part per million (ppm) or less sulfur distillate oil from the requirement to install a COMS.

C. Additional Proposed Amendments to Subpart Da

We are proposing several additional amendments to subpart Da. First, we are proposing to exempt from the requirement to install a COMS owners/operators of affected facilities subject to subpart Da that burn 500 ppm or less sulfur distillate oil. Second, we are proposing to add a provision to postpone PM performance testing for owners/operators of affected facilities that are not operating at the time a PM performance test is required to be conducted. The PM performance test would not be required until after the affected facility recommences operation. Finally, we are proposing to add a provision requiring that owners/operators of an affected facility constructed after February 28, 2005 with a wet scrubber for which the owner/operator elects to use the opacity baseline approach to monitor the performance of their primary PM control device, to maintain the liquid-to-gas flow rate at 90 percent or higher of the ratio measured during the most recent PM performance test.

D. Additional Proposed Amendments to Subpart Db

We are proposing several amendments to subpart Db. First, since synthetic natural gas derived from coal has uncontrolled emissions similar to those of natural gas, we are proposing that synthetic natural gas derived from coal be considered natural gas instead of coal under the rule. Similarly, since diesel fuel has emissions similar to distillate oil, we are proposing to include diesel fuel in the definition of distillate oil. Second, we are proposing to amend the definition of potential sulfur dioxide emission rate. This will clarify that owners/operators of boilers burning gasified coal and oil that has been desulfurized prior to combustion are able to claim credit for pretreatment reductions when using the fuel-based compliance alternatives. Third, we are proposing to amend the definition of steam generating unit to clarify that all water heaters, regardless of the mechanism used to heat the water, are covered by the NSPS. Fourth, we are proposing to change the definition of very low sulfur oil from 0.30 weight percent sulfur to 0.50 weight percent sulfur for owners/operators of affected facilities built after February 28, 2005, that are located in noncontinental areas. Finally, we are proposing to allow fuel blending to achieve the optional numerical sulfur dioxide (SO_2) limit.

We are proposing to make several amendments primarily impacting owner/operators of boilers burning coke oven gas (COG). First, we are proposing to align the regulatory test with the intent of the amendments published June 13, 2007 (72 FR 32710) and extend the 30-day SO_2 limit maintenance exemption to owners/operators of COG-fired boilers constructed prior to February 28, 2005 to include maintenance of all SO_2 control technologies in the exemption, and to require reporting of what maintenance was performed during the control device outage. We are also proposing that owners/operators of affected facilities burning gasified coal receive the same nitrogen oxide (NO_X) monitoring options as owners/operators of affected facilities burning natural gas. If adopted, this amendment would provide owners/operators of affected facilities burning gasified coal the option to develop a site-specific monitoring plan as an alternative to using a NO_X CEMS to monitor NO_X emissions.

E. Additional Proposed Amendments to Subpart Dc

We are proposing several amendments to subpart Dc. First, since synthetic natural gas derived from coal has uncontrolled emissions similar to those of natural gas, we are proposing that synthetic natural gas derived from coal be considered natural gas instead of coal. Similarly, since diesel fuel has emissions similar to those of distillate oil, we are proposing to include diesel fuel in the definition of distillate oil. Second, we are proposing to amend the definition of steam generating unit to clarify that all water heaters, regardless of the mechanism used to heat the water, are covered by the NSPS. Finally, we are proposing to allow fuel blending to achieve the optional numerical SO_2 limit.

III. Rationale for Proposed Amendments

A. Alternate Opacity Monitoring

The amendments to the new source performance standards for steam generating units promulgated on June 13, 2007 (72 FR 32710) eliminated the requirement to install and properly operate a COMS, but not the opacity standard, for owners/operators of certain affected facilities. Those affected facilities include any steam generating unit using a PM CEMS to demonstrate compliance with the applicable PM limit, oil-fired steam generating units with a carbon monoxide CEMS, steam generating units firing 500 ppm sulfur distillate oil or less (subparts Db and Dc only), and owners/operators monitoring opacity emissions under a site-specific plan approved by the permitting authority (subparts Db and Dc only). We intended in promulgating the previous amendments to provide the COMS exemption to owners/operators of steam generating units firing 500 ppm sulfur distillate oil or less across all of the subparts. However, we only added the regulatory language to subparts Db and Dc. The proposed amendments will implement the intent of the previous rulemaking by adding the language to subparts D and Da.

The previous amendments did not specify the type and frequency of alternate opacity monitoring for affected facilities that do not demonstrate compliance with the opacity limit using a COMS. Without adding specific requirements, it would be up to the permitting authority to determine the proper level of monitoring. Since the COMS exemption is only available to owner/operators of facilities continuously monitoring parameters indicative of opacity (i.e., oil-fired facilities with CO CEMS) or burning fuels with inherently low opacity (i.e., 500 ppm sulfur distillate oil-fired facilities), we are proposing to require opacity observations be done only every 12 months. However, this does not prevent the permitting authority, or any qualified individual, from performing Method 9 observation at any time to determine excess opacity. While Method 9 remains the most reliable means of determining compliance with an applicable opacity limit, we are including Method 22 as an alternative to Method 9 since it requires an observer, but not necessarily a certified Method 9 observer. This option is likely to lower the compliance burden, since an uncertified observer is able to monitor the affected facility for any visible emissions (i.e., not zero). For sources with multiple stacks, the use of a digital camera system would also reduce compliance costs, while still providing equivalent protection for the environment.

Due to the potential emissions from steam generating units, especially utility size facilities, we are specifically requesting comment on whether the frequency of the opacity observations should be increased and are considering two alternatives for the final rule. The first would increase the frequency of performance testing and require that Method 9 performance tests be completed once each calendar month or once each calendar quarter. The second alternate approach we are considering would require the owner/operator to perform either daily or weekly Method 22 (or digital photographic technique) brief observations (i.e., 5 to 15 minutes). If any visible emissions are detected, the owner/operator would be required to conduct a longer (i.e., at least 1 hour) observation to determine if the sum of the time visible emissions are present is less than 5 percent of the observation period. If the visible emissions are in excess of 5 percent of the observation period, then a Method 9 performance test would be required within 24 hours. The benefit of the frequent, but brief, Method 22 approach is that it provides more assurance than the once a year approach that the facility is operating properly, but it still keeps the compliance burden relatively low.

B. Additional Proposed Amendments to Subpart Da

We are proposing to delay the required PM performance test for facilities that are not operating at the time such a test is otherwise required because we have concluded that it is not beneficial to the environment or appropriate to require a facility to operate just to conduct a performance test. Also, in the June 13, 2007 rulemaking (72 FR 32710), we intended to include the requirement that owners/operators of an affected facility constructed after February 28, 2005 that employs a wet scrubber who choose to use a baseline opacity level to monitor PM control device performance maintain the liquid to gas ratio of the scrubber that was used during the most recent performance test. Since scrubbers can potentially impact PM emissions, we have concluded that it is necessary that the liquid to gas ratio be maintained at the same or higher level as during the performance test as part of the requirement to demonstrate continuous compliance with the PM limit. This provision is presently included in the requirements for owners/operators using a predictive electrostatic precipitator (ESP) model to monitor PM control device performance, and the proposed amendments update the regulatory text to reflect the intent of the original rulemaking.

C. Additional Proposed Amendments to Subparts Db and Dc

The intent of the alternate numerical SO_2 limit of 0.20 lb SO_2/MMBtu added in the amendments published on February 27, 2006 (71 FR 9866) was to provide flexibility to owners/operators of steam generating units burning fuels with inherently low sulfur contents. We are proposing to clarify that fuel blending with low sulfur fuels (i.e. natural gas) can be done to achieve the optional numerical SO_2 limit. The use of fuel blending decreases compliance costs for facilities. If a facility gets a single delivery of fuel with higher than expected sulfur content, the facility owner/operator can blend in low sulfur fuels to achieve the standard.

The proposal also clarifies that the term steam generating unit includes units which heat water regardless of whether the water is heated directly, indirectly, or as a heat transfer medium. The preambles to the final subpart Db rulemakings (November 25, 1986, 51 FR 42768 and 42772) and December 16, 1987 (52 FR 47826) were clear about our intent to include facilities which produce hot water without subsequently converting the water to steam in the definition of steam generating unit. Because there continues to be questions as to whether the definition of steam generating unit includes direct contact water heaters, we are taking this opportunity to confirm that "steam generating unit" includes any unit that combusts fuel and heats water, and does not categorically exclude direct contact water heaters. This clarification is not meant to reverse source-specific applicability determinations that were issued prior to today. We are also reaffirming that fuel combustion units which function as process heaters are not covered as steam generating units if their primary purpose is to heat a fluid in order to initiate or promote a chemical reaction in which the fluid itself is a reactant or catalyst. The heating of water to act as a heat transfer medium for vaporizing liquid natural gas, for example, would not generally meet the definition of a process heater.

The proposed amendments addressing steam generating units located in noncontinental areas that burn distillate oil or residual oil is based on the fact that oil containing 0.30 weight percent or less sulfur is not always readily available to owners/operators of such units, but that 0.50 weight percent sulfur distillate oil and residual oil are generally available. It was not the intent of the amendments published on February 27, 2006 (71 FR 9866) to require owners/operators of oil-fired steam generating units located in noncontinental areas to incur high fuel transportation costs or to install post combustion controls on oil-fired boilers. The proposed amendments to the definition of very low sulfur oil and the corresponding low sulfur oil PM exemption and SO_2 limit exemptions would allow owner/operators of oil-fired steam generating units located in noncontinental areas to demonstrate compliance with both limits using fuel receipts.

We are proposing that gasified coal (including COG) have the same NO_X

monitoring option as natural gas, distillate oil, and low nitrogen content residual oil since gasified coal has uncontrolled NO_X emissions similar to those of natural gas. Even though COG is a byproduct gas and not generated for the purposes of creating useful heat, it is considered coal for the purposes of subpart Db. In addition, even though the chemical compositions of COG and gasified coal that is generated for the purposes of creating useful heat are different, both have similar uncontrolled NO_X emission rates.

Because of the specific characteristics of the steel industry, the current regulations allow a 30-day exceedance per year from the SO_2 emission limit for steam generating units constructed after February 28, 2005 that burn COG exclusively or in combination with other gaseous fuels or distillate oil. COG desulfurization facilities regardless of when the steam generating units they serve were constructed require periodic maintenance, but the coking process continues during this time, and it is cost prohibitive to store the COG. Coke-making facilities would either have to install a second desulfurization unit or flare the COG and burn natural gas during the maintenance period. Of these two options, the least cost option would be to flare the COG and use natural gas during the annual maintenance. This would result in both increased cost to the steel industry and increased NO_X emissions without achieving any reductions in SO_2. We are, therefore, proposing to expand this exemption to owners/operators of COG-fired boilers constructed prior to February 28, 2005 and to the use of post-combustion controls since both pre- and post-combustion controls require maintenance. We are also proposing to add a reporting requirement to assure that any SO_2 exceedances are due to valid maintenance periods.

IV. Opacity Monitoring for Facilities With PM CEMS

There are several conditions that result in opacity from steam generating units. These include emissions of PM, NO_X, and reactions of stack gases in the atmosphere. However, opacity from NO_X emissions is rare and only occurs at high NO_X emissions rates. All modern steam generating units have inherent NO_X emissions rates below the level that would result in opacity emissions. Therefore, for modern steam generating units, the primary causes of opacity are PM and reactions of stack gases that occur after the gases are discharged to the atmosphere. PM CEMS detect solid or liquid PM at the stack conditions, and COMS detect anything that blocks light at the stack conditions. Since PM CEMS measure filterable PM (PM that is either in a solid or liquid state at the stack conditions) and COMS measure opaque material that can be used as a surrogate for particulate matter, we concluded in a previous rulemaking (71 FR 9866) that it is appropriate for owners/operators of affected facilities who use a PM CEMS (to demonstrate compliance with the applicable PM limit) to eliminate the use of COMS. However, the opacity standard itself was not eliminated, and owners/operators of facilities who elect not to install PM CEMS are required to continue to use COMS. Furthermore, it is possible that an owner/operator of an affected facility could be in compliance with the opacity limit in the stack (i.e., COMS measurements), but that a Method 9 observation could detect plume opacity violations.

Since opacity data has been used as a surrogate for PM emissions [1] and since PM CEMS give a more direct continuous measurement of the primary pollutant of interest causing opacity at steam generating units and provides data in units of the PM standard, we are requesting comment on if eliminating the opacity standard altogether for owner/operators using PM CEMS would be appropriate. However, neither a COMS nor a PM CEMS [2] detects condensable PM (i.e., PM that is in the gaseous state at the stack conditions but that will condense to form solid or liquid particulate matter at atmospheric conditions). Therefore, if we were to adopt this option and eliminate the opacity requirement for affected facilities with PM CEMS, we are proposing to require owners/operators of an affected facility with a PM CEMS to measure and electronically report filterable and condensable PM along with Method 9 opacity data (Method 9 observations of the plume opacity may detect the presence of condensable PM) during the initial and ongoing calibration of the PM CEMS. With sufficient data, we will be able to determine if a relationship exists between filterable and condensable PM and opacity and to establish direct or parametric monitoring approaches for condensable PM, including those relying on techniques other than opacity, and an appropriate condensable PM limit.

[1] Opacity is also used as an indicator of control device operation and proper maintenance.

[2] New PM CEMS are being developed that may measure condensable PM.

V. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

This action is not a ''significant regulatory action'' under the terms of Executive Order (EO) 12866 (58 FR 51735, October 4, 1993) and is, therefore, not subject to review under the EO. EPA has concluded that the amendments will not change the costs or benefits of the rule. However, EPA is requesting additional comments on the issue.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. The proposed amendments result in no changes to the information collection requirements of the existing standards of performance and would have no impact on the information collection estimate of projected cost and hour burden made and approved by the OMB during the development of the existing standards of performance. Therefore, the information collection requests have not been amended. However, OMB has previously approved the information collection requirements contained in the existing regulations (40 CFR part 60, subparts Da, Db, and Dc) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*, at the time the standards were promulgated on June 11, 1979 (40 CFR part 60, subpart Da, 44 FR 33580), November 25, 1986 (40 CFR part 60, subpart Db, 51 FR 42768), and September 12, 1990 (40 CFR part 60, subpart Dc, 55 FR 37674). OMB assigned OMB control numbers 2060–0023 for 40 CFR part 60, subpart Da, 2060–0072 for 40 CFR part 60, subpart Db, and 2060–0202 for 40 CFR part 60, subpart Dc. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act 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 this rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's regulations at 13 CFR

121.201; (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.

After considering the economic impacts of this proposed rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. This proposed rule will not impose any requirements on small entities.

We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act

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, EPA 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 one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA 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 EPA 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 EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. 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 EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that this rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. Thus, this rule is not subject to the requirements of section 202 and 205 of the UMRA. In addition, EPA determined that this rule contains no regulatory requirements that might significantly or uniquely affect small governments because the burden is small and the regulation does not unfairly apply to small governments. Therefore, this rule is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

Executive Order (EO) 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the EO to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This proposed rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in EO 13132. These proposed amendments will not impose substantial direct compliance costs on State or local governments; they will not preempt State law. Thus, EO 13132 does not apply to this rule. In the spirit of EO 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed rule from State and local officials.

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

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (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.'' This proposed rule does not have tribal implications, as specified in EO 13175. Thus, EO 13175 does not apply to this rule. EPA specifically solicits additional comment on this proposed rule from tribal officials.

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

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

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

This rule is not subject to Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355 (May 22, 2001)) because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law No. 104–113 (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. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This proposed rulemaking involves technical standards. EPA proposes to use ASTM D975–08, ''Standard Specification for Diesel Fuel Oils,'' for defining diesel fuel oil. This standard is available from the American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959.

The EPA has also decided to use EPA Method 202 (40 CFR part 51, appendix M). The Agency has not found any alternative methods. The search and review results are in the docket for this regulation.

Under 40 CFR 60.13(i) of the NSPS 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 in the final rule and amendments. 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 proposed action.

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

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

EPA has determined that this proposed rule will not have disproportionately high adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high adverse human health or environmental effects on any populations, including any minority or low-income population.

List of Subjects in 40 CFR Part 60

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

Dated: May 30, 2008.

Stephen L. Johnson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 60, of the Code of the Federal Regulations is proposed to be amended as follows:

PART 60—[AMENDED]

1. The authority citation for part 60 continues to read as follows:

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

Subpart A—[Amended]

2. Section 60.17 is amended by redesignating paragraphs (a)(17) through (a)(92) as paragraphs (a)(18) through (a)(93) and by adding new paragraph (a)(17) to read as follows:

§ 60.17 Incorporations by Reference.

* * * * *

(17) ASTM D975–08, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.41(b) of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

Subpart D—[Amended]

3. Section 60.43 is amended by revising paragraph (d) to read as follows:

§ 60.43 Standard for sulfur dioxide (SO_2).

* * * * *

(d) As an alternate to meeting the requirements of paragraphs (a) and (b) of this section, an owner or operator can petition the Administrator (in writing) to comply with § 60.43Da(i)(3) of subpart Da of this part or comply with § 60.42b(k)(4) of subpart Db of this part, as applicable to the affected source. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in § 60.43Da(i)(3) of subpart Da of this part or § 60.42b(k)(4) of subpart Db of this part, as applicable to the affected source.

* * * * *

4. Section 60.45 is amended to read as follows:

a. By revising paragraph (b)(1) and adding new paragraph (b)(7); and

b. By revising paragraphs (g)(2),(g)(3), and (g)(4).

§ 60.45 Emissions and fuel monitoring.

* * * * *

(b) * * *

(1) For a fossil-fuel-fired steam generator that burns only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2 or PM, CEMS for measuring the opacity of emissions and SO_2 emissions are not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis or fuel receipts.

* * * * *

(7) The owner or operator of an affected facility subject to an opacity standard under § 60.42 and that elects to not install a CEMS for measuring opacity because the affected facility burns only fuels as specified under paragraph (b)(1) of this section, monitors PM emissions as specified under paragraph (b)(5) of this section, or monitors CO emissions as specified under paragraph (b)(6) of this section shall comply with either paragraphs (b)(7)(i), (b)(7)(ii), or (b)(7)(iii) of this section.

(i) Conduct a performance test using Method 9 of Appendix A–4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.42. The Method 9 observations must be completed, at a minimum, every 12 months; or

(ii) Conduct a series of three 1-hour observations (during normal operation) using Method 22 of Appendix A–7 of this part at the affected facility and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (i.e., 9 minutes per 3-hour period). The Method 22 observations must be completed, at a minimum, every 12 months. If the sum of the occurrences of visible emissions in excess of 5 percent of the observation period, then the owner or operator shall conduct a performance test within 24 hours according to the requirements in § 60.46(a)(3); or

(iii) Monitor opacity using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations should include at least one digital image every 15 seconds for three separate 1-hour periods (during normal operation) every 12 months. An approvable monitoring plan should include a demonstration that the occurrences of visible emissions are not in excess of 5 percent of the observation period (i.e., 36 observations per 3-hour period). For reference purposes in preparing the monitoring plan, see OAQPS ''Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.'' This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods. If the sum of the occurrences of any visible emissions is in excess of 5 percent of the observation period, then the owner or operator shall conduct a new performance test within

24 hours according to the requirements in § 60.46(a)(3).

* * * * *

(g) * * *

(2) *Sulfur dioxide*. Excess emissions for affected facilities are defined as:

(i) For affected facilities electing not to comply with § 60.43(d), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard under § 60.43; or

(ii) For affected facilities electing to comply with § 60.43(d), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO_2 as measured by a CEMS exceed the applicable standard under § 60.43. Facilities complying with the 30-day SO_2 standard shall use the most current associated SO_2 compliance and monitoring requirements in §§ 60.48Da and 60.49Da of subpart Da of this part or §§ 60.45b and 60.47b of subpart Db of this part, as applicable.

(3) *Nitrogen oxides.* Excess emissions for affected facilities using a CEMS for measuring NO_X are defined as:

(i) For affected facilities electing not to comply with § 60.44(e), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under § 60.44; or

(ii) For affected facilities electing to comply with § 60.44(e), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO_X as measured by a CEMS exceed the applicable standard under § 60.44. Facilities complying with the 30-day NO_X standard shall use the most current associated NO_X compliance and monitoring requirements in §§ 60.48Da and 60.49Da of subpart Da of this part.

(4) *Particulate matter.* Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating day period during which the average emissions (arithmetic average of all operating one-hour periods) exceed the applicable standards under § 60.42. Affected facilities using PM CEMS in lieu of a CEMS for monitoring opacity emissions must follow the most current applicable compliance and monitoring provisions in §§ 60.48Da and 60.49Da of subpart Da of this part.

5. Section 60.46 is amended by revising paragraph (b)(2) introductory text to read as follows:

§ 60.46 Test methods and procedures.

* * * * *

(b) * * *

(2) Method 5 of appendix A–3 of this part shall be used to determine PM concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B of appendix A–3 of this part shall be used to determine the PM concentration (C) after FGD systems. Method 5 or 5B of appendix A–3 of this part, Method 17 of appendix A–6 of this part may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 2.1 and 2.3 of Method 5B of appendix A–3 of this part may be used with Method 17 of appendix A–6 of this part only if it is used after wet FGD systems. Method 17 of appendix A–6 of this part shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

* * * * *

Subpart Da—[Amended]

6. Section 60.40Da is amended by revising paragraph (b)(4) to read as follows:

§ 60.40Da Applicability and designation of affected facility.

* * * * *

(b) * * *

(4) Heat recovery steam generators that are associated with combined cycle gas turbines that meet the applicability requirements of subpart KKKK of this part are not subject to this part. This subpart will continue to apply to all other electric utility combined cycle gas turbines that are capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel in the heat recovery steam generator. If the heat recovery steam generator is subject to this subpart and the stationary combustion turbine is subject to either subpart GG or KKKK of this part, only emissions resulting from combustion of fuels in the steam-generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

* * * * *

7. Section 60.41Da is amended in paragraph (c) by revising the definitions of ''Gross output,'' ''Petroleum,'' and ''Potential combustion concentration'' to read as follows:

§ 60.41Da Definitions.

* * * * *

(c) * * *

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output, measured relative to ISO conditions, that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process).

* * * * *

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, residual oil, and petroleum coke.

Potential combustion concentration means the theoretical emissions (nanograms per joule (ng/J), lb/MMBtu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems and:

* * * * *

8. Section 60.48Da is amended to read as follows:

a. By revising paragraph (n);

b. By revising paragraphs (o) introductory text, (o)(1), (o)(2)(ii) introductory text, (o)(2)(iii), (o)(2)(iv), (o)(2)(vi), (o)(3)(i), (o)(3)(iii), and (o)(5); and

c. By adding paragraph (q).

§ 60.48Da Compliance provisions.

* * * * *

(n) *Compliance provisions for sources subject to § 60.42Da(c)(1).* The owner or operator of an affected facility subject to § 60.42Da(c)(1) shall calculate PM emissions by multiplying the average hourly PM output concentration (measured according to the provisions of § 60.49Da(t)), by the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), and divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)). Compliance with the emission limit is determined by calculating the arithmetic average of the hourly emission rates computed for each boiler operating day.

(o) *Compliance provisions for sources subject to § 60.42Da(c)(2) or (d).* Except as provided for in paragraph (p) of this section and § 60.49Da(a)(2), the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, shall demonstrate compliance with each applicable emission limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section.

(1) You must conduct a performance test to demonstrate initial compliance with the applicable PM emissions limit in § 60.42Da(c)(2) or (d) by the applicable date specified in § 60.8(a). Thereafter, you must conduct each subsequent performance test within 12 calendar months following the date the previous performance test was required to be conducted. You must conduct each performance test according to the requirements in § 60.8 using the test methods and procedures in § 60.50Da. An affected facility that has not operated for 2 months prior to the due date of a performance test is not required to perform the subsequent performance test until 60 days after the next boiler operating day.

(2) * * *

(ii) You must comply with the quality assurance requirements in paragraphs (o)(2)(ii)(A) through (E) of this section.

* * * * *

(iii) During each performance test conducted according to paragraph (o)(1) of this section, you must establish an opacity baseline level. The value of the opacity baseline level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurements recorded during each of the test run intervals conducted for the performance test, and then adding 2.5 percent opacity to your calculated average opacity value for all of the test runs. If your opacity baseline level is less than 5.0 percent, then the opacity baseline level is set at 5.0 percent.

(iv) You must evaluate the preceding 24-hour average opacity level measured by the COMS each boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the measured 24-hour average opacity emission level is greater than the baseline opacity level determined in paragraph (o)(2)(iii) of this section, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high opacity incident and take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the measured 24-hour average opacity to a level below the baseline opacity level. In cases when a wet scrubber is used alone or in combination with another PM control device to comply with the PM emissions limit, the daily average liquid-to-gas flow rate for the wet scrubber must be maintained at least at 90 percent of average ratio measured during all test run intervals for the performance test conducted according to paragraph (o)(1) of this section.

* * * * *

(vi) If the measured 24-hour average opacity for your affected facility remains at a level greater than the opacity baseline level after 7 boiler operating days, then you must conduct a new PM performance test according to paragraph (o)(1) of this section and establish a new opacity baseline value according to paragraph (o)(2) of this section. This new performance test must be conducted within 60 days of the date that the measured 24-hour average opacity was first determined to exceed the baseline opacity level unless a waiver is granted by the permitting authority.

(3) * * *

(i) You must calibrate the ESP predictive model with each PM control device used to comply with the applicable PM emissions limit in § 60.42Da(c)(2) or (d) operating under normal conditions. In cases when a wet scrubber is used in combination with an ESP to comply with the PM emissions limit, the daily average liquid-to-gas flow rate for the wet scrubber must be maintained at least at 90 percent of average ratio measured during all test run intervals for the performance test conducted according to paragraph (o)(1) of this section.

* * * * *

(iii) You must run the ESP predictive model using the applicable input data each boiler operating day and evaluate the model output for the preceding boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the values for one or more of the model parameters exceed the applicable baseline levels determined according to your approved site-specific monitoring plan, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of a model parameter deviation and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to return the model output to within the applicable baseline levels.

* * * * *

(5) An owner or operator of a modified affected facility electing to meet the emission limitations in § 60.42Da(d) shall determine the percent reduction in PM by using the emission rate for PM determined by the performance test conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

* * * * *

(q) *Compliance provisions for sources subject to § 60.42Da(b).* An owner or operator of an affected facility subject to the opacity standard under § 60.42Da(b) shall meet the requirements in paragraphs (q)(1) and (2) of this section.

(1) Demonstrate compliance of the affected facility with the opacity limit in § 60.42Da(b) initially and, thereafter, except as provided in paragraphs § 60.49Da(a)(3)(ii) and (iii), at least once every 12 months according to the requirements in § 60.50Da(b)(3), and

(2) Monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the requirements in § 60.49Da(a), as applicable to the affected facility.

9. Section 60.49Da is amended to read as follows:

a. By revising paragraph (a);

b. By revising paragraph (t);

c. By revising paragraph (u);

d. By revising paragraph (v); and

e. By revising paragraph (w)(2).

§ 60.49Da Emission monitoring.

(a) An owner or operator of an affected facility subject to the opacity standard under § 60.42Da(b) shall monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the applicable requirements in paragraphs (a)(1) through (3) of this section.

(1) Except as provided for in paragraph (a)(2) of this section, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere (i.e., install, calibrate, maintain, and operate a COMS). If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the SO_2 control system), alternate parameters indicative of the PM control system's performance and/or good combustion are monitored (subject to the approval of the Administrator).

(2) An owner or operator of an affected facility that meets the conditions in either paragraph (a)(2)(i), (ii), or (iii) of this section may elect to comply with the requirements of paragraph (a)(3) of this section as an alternative to the monitoring

requirements in paragraph (a)(1) of this section.

(i) The affected facility uses a CEMS for measuring PM emissions to demonstrate continuous compliance on a boiler operating day average with the emissions limitations under §§ 60.42Da(a)(1), 60.42Da(c)(1), or 60.42Da(c)(2), and the PM CEMS is installed, certified, operated, and maintained on the affected facility according to the requirements of paragraph (v) of this section; or

(ii) The affected facility burns only gaseous or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and does not use a post-combustion technology to reduce emissions of SO_2 or PM; or

(iii) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis. Owners and operators of affected facilities electing to comply with this paragraph must use a CEMS measuring CO emissions and demonstrate compliance according to the procedures specified in paragraph (u) of this section.

(3) The owner or operator of an affected facility that meets the conditions in paragraph (a)(2) of this section shall monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the requirements in either paragraph (a)(3)(i), (ii), or (iii) of this section,

(i) Conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in § 60.11 to demonstrate compliance with the limit in § 60.42Da(b). The Method 9 observations must be completed, at a minimum, every 12 months; or

(ii) Conduct a series of three 1-hour observations (during normal operation) using Method 22 of appendix A–7 of this part at the affected facility and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (i.e., 9 minutes per 3-hour period). The Method 22 observations must be completed, at a minimum, every 12 months. If the sum of the occurrences of any visible emissions is in excess of 5 percent of the observation period, then the owner or operator shall conduct a new performance test within 24 hours according to the requirements in § 60.50Da(b)(3); or

(iii) Monitor opacity using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations should include at least one digital image every 15 seconds for three separate 1-hour periods (during normal operation) every 12 months. An approvable monitoring plan should include a demonstration that the occurrences of visible emissions are not in excess of 5 percent of the observation period (i.e., 36 observations per 3-hour period). For reference purposes in preparing the monitoring plan, see OAQPS ''Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.'' This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods. If the sum of the occurrences of any visible emissions is in excess of 5 percent of the observation period, then the owner or operator shall conduct a new performance test within 24 hours according to the requirements in § 60.50Da(b)(3).

* * * * *

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under § 60.42Da(c)(1) shall install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected facility demonstrating compliance with the input-based emission limitation under § 60.42Da(a)(1) or § 60.42Da(c)(2) may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) The owner or operator of an affected facility using a CEMS measuring CO emissions to meet requirements of this subpart shall meet the requirements specified in paragraphs (u)(1) through (4) of this section.

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (u)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each boiler operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly useful energy output from the affected facility. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each boiler operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected facility startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 1.4 lb/MWh, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 1.4 lb/MWh or less.

(4) You must record the CO measurements and calculations performed according to paragraph (u)(3) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 1.4 lb/MWh, and the date, time, and description of the corrective action.

(v) The owner or operator of an affected facility using a CEMS measuring PM emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (v)(1) through (v)(4) of this section.

(1) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of § 60.13, Performance

Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each PM correlation testing run of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using the following test methods.

(i) For PM, Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall be used; and

(ii) For condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and

(iii) For visible emissions, Method 9 of Appendix A–4 shall be used; and

(iv) For O_2 (or CO_2), Method 3, 3A, or 3B of appendix A–2 of this part, as applicable shall be used.

(3) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audits must be performed annually and Response Correlation Audits must be performed every 3 years.

(4) Within 90 days after the date of completing each performance evaluation required by paragraph (v) of this section, the owner or operator of the affected facility must submit the test data to EPA by successfully entering the data electronically into EPA's WebFire data base available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main*. If the owner or operator is unsuccessful in entering the test data into EPA's WebFire data base, then the owner or operator must submit monthly reports to EPA until the data is successfully submitted to WebFire. The monthly reports shall describe the difficulty preventing successful submittal of the data and what actions are being taken to correct the problem.

(w) * * *

(2) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to implement the following alternative data accuracy assessment procedures. For all required CO_2 and O_2 CEMS and for SO_2 and NO_X CEMS with span values greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F of this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to SO_2 and NO_X span values less than 100 ppm;

* * * * *

10. Section 60.50Da is amended by revising paragraph (f) to read as follows:

§ 60.50Da Compliance determination procedures and methods.

* * * * *

(f) Electric utility combined cycle gas turbines that are not designed and intended to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas on a 12-month rolling average are performance tested for PM, SO_2, and NO_X using the procedures of Method 19 of appendix A–7 of this part. The SO_2 and NO_X emission rates from the gas turbine used in the Method 19 calculations are determined when the gas turbine is performance tested under subpart GG of this part. The potential uncontrolled PM emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/MMBtu) heat input.

* * * * *

Subpart Db—[Amended]

11. Section 60.40b is amended by revising paragraph (i) to read as follows:

§ 60.40b Applicability and delegation of authority.

* * * * *

(i) Heat recovery steam generators that are associated with combined cycle gas turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

* * * * *

12. Section 60.41b is amended in paragraph by revising the definitions of ''Coal,'' ''Distillate oil,'' ''Gaseous fuel,'' ''Gross output,'' ''Natural gas,'' ''Potential sulfur dioxide emission rate,'' ''Pulverized coal-fired steam generating unit,'' ''Steam generating unit,'' and ''Very low sulfur oil'' to read as follows:

§ 60.41b Definitions.

* * * * *

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

* * * * *

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17) or diesel fuel oil as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17).

* * * * *

Gaseous fuel means any fuel that is present as a gas at ISO conditions. This includes, but is not limited to, natural gas and gasified coal (including coke oven gas).

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output, measured relative to ISO conditions, that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process).

* * * * *

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic

meter (910 and 1,150 Btu per dry standard cubic foot).

* * * * *

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems. For gasified coal or oil that is desulfurized prior to combustion, the *Potential sulfur dioxide emission rate* is the theoretical SO_2 emissions (ng/J or lb/MMBtu heat input) that would result from combusting fuel in a cleaned state without using any post combustion emission control systems.

* * * * *

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units.

* * * * *

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

* * * * *

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, an oil that contains no more than 0.50 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 215 ng/J (0.50 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and not located in a noncontinental area, *very low sulfur oil* means an oil that contains no more than 0.30 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and located in a noncontinental area, *very low sulfur oil* means an oil that contains no more than 0.50 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 215 ng/J (0.50 lb/MMBtu) heat input.

* * * * *

13. Section 60.42b is amended to read as follows:

a. By revising paragraph (a);
b. By revising paragraph (b);
c. By revising paragraph (c);
d. By revising paragraph (d) introductory text; and
e. By revising paragraphs (k)(1), (2), and (3).

§ 60.42b Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), (d), or (j) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and the emission limit determined according to the following formula:

$$E_s = \frac{(K_a * H_a + K_b * H_b)}{H_a + H_b}$$

Where:

E_s = SO_2 emission limit, in ng/J or lb/MMBtu heat input;
K_a = 520 ng/J (or 1.2 lb/MMBtu);
K_b = 340 ng/J (or 0.80 lb/MMBtu);
H_a = Heat input from the combustion of coal, in J (MMBtu); and
H_b = Heat input from the combustion of oil, in J (MMBtu).

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable. For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(c) On and after the date on which the performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of SO_2 emissions, shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 50 percent of the potential SO_2 emission rate (50 percent reduction) and that contain SO_2 in excess of the emission limit determined according to the following formula:

$$E_s = \frac{(K_c * H_c + K_d * H_d)}{H_c + H_d}$$

Where:

E_s = SO_2 emission limit, in ng/J or lb/MMBtu heat input;
K_c = 260 ng/J (or 0.60 lb/MMBtu);
K_d = 170 ng/J (or 0.40 lb/MMBtu);
H_c = Heat input from the combustion of coal, in J (MMBtu); and
H_d = Heat input from the combustion of oil, in J (MMBtu).

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section. For facilities complying with paragraphs (d)(1), (2), or (3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

* * * * *

(k)(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2 emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. For facilities complying with the percent reduction standard and paragraph (k)(3), only the heat input supplied to the affected facility from the combustion of coal and oil is counted under paragraph (k) of this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(2) Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2 emissions limit in paragraph 60.42b(k)(1).

(3) Units that are located in a noncontinental area and that combust coal, oil, or natural gas shall not discharge any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil or natural gas.

* * * * *

14. Section 60.43b is amended to read as follows:

a. By revising paragraph (f);

b. By revising paragraphs (h)(1), (h)(5), and adding new paragraph (h)(6).

§ 60.43b Standard for particulate matter (PM).

* * * * *

(f) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that can combust coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

* * * * *

(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5), and (h)(6) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input.

* * * * *

(5) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility not located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.30 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard under § 60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits under § 60.43b(h)(1).

(6) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard under § 60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits under § 60.43b(h)(1).

15. Section 60.44b is amended by revising paragraph (l)(1) to read as follows:

§ 60.44 Standard for nitrogen oxides (NO_X).

* * * * *

(l) * * *

(1) If the affected facility combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels: A limit of 86 ng/J (0.20 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or

* * * * *

16. Section 60.45b is amended to read as follows:

a. By revising paragraph (a);

b. By revising paragraph (d) introductory text;

c. By revising paragraph (j); and

d. By revising paragraph (k).

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The SO_2 emission standards under § 60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil are allowed to exceed the limit 30 operating days per calendar year for SO_2 control system maintenance.

* * * * *

(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, natural gas, or a mixture of these fuels, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

* * * * *

(j) The owner or operator of an affected facility that only combusts very low sulfur oil, natural gas, or a mixture of these fuels with any other fuels not subject to an SO_2 standard is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in § 60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance under §§ 60.42b(d)(4), 60.42b(j), 60.42b(k)(2), and 60.42b(k)(3) (when not burning coal) shall follow the applicable procedures under § 60.49b(r).

17. Section 60.46b is amended to read as follows:

a. By revising paragraphs (e)(2) and (e)(4);

b. By revising paragraph (i);

c. By revising paragraphs (j) introductory text and (j)(11) and adding new paragraph (j)(14) to read as follows:

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

* * * * *

(e) * * *

(2) Following the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal (except as specified under § 60.46b(e)(4)) or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the NO_X emission standards under § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

* * * * *

(4) Following the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_X standards under § 60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_X emissions data collected pursuant to § 60.48b(g)(1) or § 60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_X emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

* * * * *

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the PM limit under paragraphs § 60.43b(a)(4) or § 60.43b(h)(5) shall follow the applicable procedures under § 60.49b(r).

(j) In place of PM testing with Method 5 or 5B of appendix A–3 of this part, or Method 17 of appendix A–6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(14) of this section.

* * * * *

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and conducting performance tests using the following test methods.

(i) For PM, Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall be used; and

(ii) For condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and

(iii) For visible emissions, Method 9 of Appendix A–4 shall be used; and

(iv) For O_2 (or CO_2), Method 3, 3A, or 3B of appendix A–2 of this part, as applicable shall be used.

* * * * *

(14) Within 90 days after the date of completing each performance evaluation required by paragraph (c)(11) of this section, the owner or operator of the affected facility must submit the test data to EPA by successfully entering the data electronically into EPA's WebFire data base available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main.* If the owner or operator is unsuccessful in entering the test data into EPA's WebFire data base, then the owner or operator must submit monthly reports to EPA until the data is successfully submitted to WebFire. The monthly reports shall describe the difficulty preventing successful submittal of the data and what actions are being taken to correct the problem.

18. Section 60.47b is amended by revising paragraphs (a) introductory text and (e)(4)(i) to read as follows:

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the SO_2 standards under § 60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the SO_2 and either O_2 or CO_2 concentrations shall both be monitored at the inlet and outlet of the SO_2 control device. If the owner or operator has installed and certified SO_2 and O_2 or CO_2 CEMS according to the requirements of § 75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of § 75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

* * * * *

(e) * * *

(4) * * *

(i) For all required CO_2 and O_2 monitors and for SO_2 and NO_X monitors with span values greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to SO_2 and NO_X span values less than 100 ppm;

* * * * *

19. Section 60.48b is amended to read as follows:

a. By revising paragraph (a);

b. By revising paragraph (g) introductory text;

c. By revising paragraph (h) introductory text; and

d. By revising paragraph (k) introductory text.

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a COMS for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under § 60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), or (4) of this section who elects not to install a COMS shall comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section.

(1) Conduct a performance test using Method 9 of Appendix A–4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43b. The Method 9 observations must be completed, at a minimum, every 12 months; or

(2) Conduct a series of three 1-hour observations (during normal operation) using Method 22 of Appendix A–7 of this part at the affected facility and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (i.e., 9 minutes per 3-hour period). The Method 22 observations must be completed, at a minimum, every 12 months. If the sum of the occurrences of any visible emissions is in excess of 5 percent of the observation period, then the owner or operator shall conduct a new performance test within 24 hours according to the requirements in § 60.46b(d)(7); or

(3) Monitor opacity using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations should include at least one digital image every 15 seconds for three separate 1-hour periods (during normal operation) every 12 months. An approvable monitoring plan should include a demonstration that the occurrences of visible emissions are not in excess of 5 percent of the observation period (i.e., 36 observations per 3-hour period). For reference purposes in preparing the monitoring plan, see OAQPS ''Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.'' This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods. If the sum of the occurrences of any visible emissions is in excess of 5 percent of the observation period, then the owner or operator shall conduct a new performance test within 24 hours according to the requirements in § 60.46b(d)(7).

* * * * *

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall:

* * * * *

(h) The owner or operator of a duct burner, as described in § 60.41b, that is subject to the NO_X standards of § 60.44b(a)(4), § 60.44b(e), or § 60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NO_X emissions.

* * * * *

(k) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in § 60.46b(j). The CEMS specified in paragraph § 60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

20. Section 60.49b is amended to read as follows:

a. By revising paragraphs (c) introductory text and (c)(3);

b. By revising paragraphs (h) introductory text, (h)(1),(h)(2) introductory text and (h)(2)(i);

c. By revising paragraph (k)(2); and

d. By revising paragraph (r) introductory text and(r)(1).

§ 60.49b Reporting and recordkeeping requirements.

* * * * *

(c) The owner or operator of each affected facility subject to the NO_X standard of § 60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions under the provisions of § 60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored under § 60.48b(g)(2) and the records to be maintained under § 60.49b(h). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. An affected facility burning coke oven gas alone or in combination with other gaseous fuels or distillate oil shall submit this plan to the Administrator for approval within 360 days of the initial startup of the affected facility or by May 31, 2009, whichever date comes later. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

* * * * *

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under § 60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under § 60.49b(h).

* * * * *

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards under § 60.43b(f) or to the operating parameter monitoring requirements under § 60.13(i)(1).

(2) Any affected facility that is subject to the NOX standard of § 60.44b, and that:

(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

* * * * *

(k) * * *

(2) Each 30-day average SO2 emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period;

reasons for noncompliance with the emission standards; and a description of corrective actions taken; For an exceedance due to maintenance of the SO2 control system covered under paragraph 60.45b(a), the report shall identify the days on which the maintenance was performed and a description of the maintenance;

* * * * *

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in § 60.42b or § 60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil and/or natural gas under § 60.42b(j) or § 60.42b(k) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in § 60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition and/or natural gas was combusted in the affected facility during the reporting period; or

* * * * *

Subpart Dc—[Amended]

21. Section 60.41c is amended by revising the definitions of ''Coal,'' ''Distillate oil,'' ''Natural gas,'' and ''Steam generating unit'' to read as follows:

§ 60.41c Definitions.

* * * * *

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

* * * * *

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17) or diesel fuel oil as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17).

* * * * *

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

* * * * *

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

* * * * *

22. Section 60.42c is amended by revising paragraphs (e)(2) and (j) to read as follows:

§ 60.42c Standard for sulfur dioxide (SO_2).

* * * * *

(e) * * *

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = \frac{\left(K_a * H_a + K_b * H_b + K_c * H_c\right)}{\left(H_a + H_b + H_c\right)}$$

Where:

E_s= SO_2 emission limit, expressed in ng/J or lb/MMBtu heat input;

K_a = 520 ng/J (1.2 lb/MMBtu);

K_b = 260 ng/J (0.60 lb/MMBtu);

K_c = 215 ng/J (0.50 lb/MMBtu);

H_a = Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

H_b = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

H_c = Heat input from the combustion of oil, in J (MMBtu).

* * * * *

(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

23. Section 60.43c is amended by revising paragraph (c) to read as follows:

§ 60.43c Standard for particulate matter (PM).

* * * * *

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that can combust coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

* * * * *

24. Section 60.44c is amended by revising paragraph (h) to read as follows:

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

* * * * *

(h) For affected facilities subject to § 60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described under § 60.48c(f), as applicable.

* * * * *

25. Section 60.45c is amended to read as follows:

a. By revising paragraph (a)(8);

b. By revising paragraphs (c) introductory text, (c)(7), (c)(8), (c)(9), (c)(11), and adding new paragraph (c)(14) to read as follows:

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

(a) * * *

(8) Method 9 of appendix A–4 of this part shall be used for determining the opacity of stack emissions.

* * * * *

(c) In place of PM testing with Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

* * * * *

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (c)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (c)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under § 60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (c)(7) of this section are not met.

* * * * *

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and conducting performance tests using the following test methods.

(i) For PM, Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall be used; and

(ii) For condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and

(iii) For visible emissions, Method 9 of Appendix A–4 shall be used; and

(iv) For O_2 (or CO_2), test Method 3, 3A, or 3B of appendix A–2 of this part, as applicable shall be used.

* * * * *

(14) Within 90 days after the date of completing each performance evaluation required by paragraph (c)(11) of this section, the owner or operator of the affected facility must submit the test data to EPA by successfully entering the data electronically into EPA's WebFire data base available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main*. If the owner or operator is unsuccessful in entering the test data into EPA's WebFire data base, then the owner or operator must submit monthly reports to EPA until the data is successfully submitted to WebFire. The monthly reports shall describe the difficulty preventing successful submittal of the data and what actions are being taken to correct the problem.

* * * * *

26. Section 60.47c is amended to read as follows:

a. By revising paragraph (a);

b. By revising paragraph (c) introductory text;

c. By revising paragraph (d) introductory text;

d. By revising paragraph (e) introductory text; and

e. By revising paragraph (f) introductory text.

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under § 60.43c(c) and that is not required to install a COMS to measure opacity due to paragraphs (c), (d), or (e) of this section that elects not to install a COMS shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section.

(1) Conduct a performance test using Method 9 of Appendix A–4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43c. The Method 9 observations must be completed, at a minimum, every 12 months; or

(2) Conduct a series of three 1-hour observations (during normal operation) using Method 22 of Appendix A–7 of this part at the affected facility and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (i.e., 9 minutes per 3-hour period). The Method 22 observations must be completed, at a minimum, every 12 months. If the sum of the occurrences of any visible emissions is in excess of 5 percent of the observation period, then the owner or operator shall conduct a new performance test within 24 hours according to the requirements in § 60.45c(a)(8); or

(3) Monitor opacity using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations should include at least one digital image every 15 seconds for three separate 1-hour periods (during normal operation) every 12 months. An approvable monitoring plan should include a demonstration that the occurrences of visible emissions are not in excess of 5 percent of the observation period (i.e., 36 observations per 3-hour period). For reference purposes in preparing the monitoring plan, see OAQPS ''Determination of Visible Emission Opacity From Stationary Sources Using Computer-Based Photographic Analysis Systems.'' This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods. If the sum of the occurrences of any visible emissions is in excess of 5 percent of the observation period, then the owner or operator shall conduct a new performance test within 24 hours according to the requirements in § 60.450c(a)(8).

* * * * *

(c) Affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.06 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO_2 or PM emissions and that are subject to an opacity standard under § 60.43c(c) are not required to operate a CEMS for measuring opacity if they follow the applicable procedures under § 60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in § 60.45c(c). The CEMS specified in paragraph § 60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) An affected facility that is subject to an opacity standard under § 60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.50 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS for measuring opacity. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section.

* * * * *

(f) An affected facility that is subject to an opacity standard under § 60.43c(c) and that burns only gaseous fuels or fuel oils that contain less than or equal to 0.50 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS for measuring opacity. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

27. Section 60.48c is amended by revising paragraph (e)(11) to read as follows:

§ 60.48c Reporting and Recordkeeping requirements.

* * * * *

(e) * * *

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

* * * * *

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