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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[OAR–2005–0031; FRL–7873–8]

RIN 2060–AM80

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 amendments.

SUMMARY: Pursuant to section 111(b)(1)(B) of the Clean Air Act (CAA), the EPA has reviewed the emission standards for particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NO_X) contained in the standards of performance for electric utility steam generating units, industrial-commercial-institutional steam generating units, and small industrial-commercial-institutional steam generating units. This action presents the results of EPA's review and proposes amendments to standards consistent with those results. Specifically, we are proposing amendments to the PM, SO_2, and NO_X emission standards. We are also proposing to replace the current percent reduction requirement for SO_2 with an output-based SO_2 emission limit. We are also proposing an amendment to the PM emission limit. In addition to amending the emissions limits, we also are proposing several technical clarifications and corrections to existing provisions of the current rules.

DATES: Comments on the proposed amendments must be received on or before April 29, 2005.

Public Hearing: If anyone contacts EPA by March 21, 2005, requesting to speak at a public hearing, EPA will hold a public hearing on March 30, 2005. Persons interested in attending the public hearing should contact Ms. Eloise Shepherd at (919) 541–5578 to verify that a hearing will be held.

ADDRESSES: Submit your comments, identified by Docket ID

No. OAR–2005–0031, by one of the following methods: *Federal eRulemaking Portal: http://www.regulations.gov*. Follow the on-line instructions for submitting comments. *Agency Web site: http://www.epa.gov/edocket*. EDOCKET, EPA's electronic public docket and comment system, is EPA's preferred method for receiving comments. Follow the on-line instructions for submitting comments.

E-mail: Send your comments via electronic mail to *a-and-r-docket@epa.gov*, Attention Docket ID No. OAR–2005–0031.

By Facsimile: Fax your comments to (202) 566–1741, Attention Docket ID No. OAR–2005–0031.

Mail: Send your comments to: EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode 6102T, 1200 Pennsylvania Ave., NW., Washington, DC 20460, Attention Docket ID No. OAR–2005–0031. Please include a total of two copies. The EPA requests a separate copy also be sent to the contact person identified below (*see* **FOR FURTHER INFORMATION CONTACT**). 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 St., NW., Washington, DC 20503.

Hand Delivery: Deliver your comments to: EPA Docket Center (EPA/DC), EPA West Building, Room B108, 1301 Constitution Ave., NW., Washington, DC, Attention Docket ID No. OAR–2005–0031. Such deliveries are accepted only during the normal hours of operation (8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays), and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. OAR–2005–0031. The 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.epa.gov/edocket*, 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 EDOCKET, regulations.gov, or e-mail. The EPA EDOCKET and the Federal regulations.gov Web sites are ''anonymous access'' systems, 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 EDOCKET or *regulations.gov*, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Public Hearing: If a public hearing is held, it will be held at EPA's Campus located at 109 T.W. Alexander Drive in Research Triangle Park, NC, or an alternate site nearby.

Docket: All documents in the docket are listed in the EDOCKET index at *http://www.epa.gov/edocket*. Although listed in the index, some information is not publicly available, *i.e.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in EDOCKET or in hard copy at the EPA Docket Center (EPA/DC), EPA West Building, Room B102, 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 EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Christian Fellner, Combustion Group, Emission Standards Division (C439–01), U.S. EPA, Research Triangle Park, North Carolina 27711, (919) 541–4003, e-mail *fellner.christian@epa.gov*.

SUPPLEMENTARY INFORMATION:

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

I. General Information

A. Does This Action Apply to Me?

Regulated Entities. Categories and entities potentially regulated by the proposed amendments are new electric utility steam generating units and new, reconstructed, and modified industrial-commercial-institutional steam generating units. The proposed amendments would affect the following categories of sources:

Category	NAICS code	SIC code	Examples of potentially 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 steam generating units in Indian Country.
Any industrial-commercial-institutional facility using a boiler as defined in CFR 60.40b or CFR 60.40c.	211	13	Extractors of crude petroleum and natural gas.
	321	24	Manufacturers of lumber and wood products.
	322	26	Pulp and paper mills.
	325	28	Chemical manufacturers.
	324	29	Petroleum refiners and manufacturers of coal products.
	316, 326, 339	30	Manufacturers of rubber and miscellaneous plastic products.
	331	33	Steel works, blast furnaces.
	332	34	Electroplating, plating, polishing, anodizing, and coloring.
	336	37	Manufacturers of motor vehicle parts and accessories.
	221	49	Electric, gas, and sanitary services.
	622	80	Health services.
	611	82	Educational Services.

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

B. What Should I Consider as I Prepare My Comments for EPA?

1. *Submitting CBI.* Do not submit information that you consider to be confidential business information (CBI) electronically through EDocket, regulations.gov, or e-mail. Send or deliver information identified as CBI only to the following address: Mr. Christian Fellner, c/o OAQPS Document Control Officer (Room C404–02), U.S. EPA, Research Triangle Park, 27711, Attention Docket ID No. OAR–2005–0031. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD ROM that you mail to EPA, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

If you have any questions about CBI or the procedures for claiming CBI, please consult the person identified in the **FOR FURTHER INFORMATION CONTACT** section.

2. *Tips for Preparing Your Comments.* When submitting comments, remember to:

a. Identify the proposed amendments by docket number and other identifying information (subject heading, **Federal Register** date and page number).

b. Follow directions. The EPA may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

c. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

d. Describe any assumptions and provide any technical information and/

or data that you used in formulating your comments.

e. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

f. Provide specific examples to illustrate your concerns, and suggest alternatives.

g. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

h. Make sure to submit your comments by the comment period deadline identified.

Docket. The docket number for the proposed amendments to the standards of performance (40 CFR part 60, subpart Da, Db, and Dc) is Docket ID No. OAR–2005–0031. Other dockets incorporated by reference for the standards of performance include Docket ID Nos. A–79–02, A–83–27, A–86–02, and A–92–71.

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of the proposed amendments is available on the WWW through the Technology Transfer Network (TTN). Following signature, EPA will post a copy of the proposed amendments on the TTN's policy and guidance page for newly proposed or promulgated amendments at *http://www.epa.gov/ttn/oarpg*. The TTN provides information and technology exchange in various areas of air pollution control. If more information regarding the TTN is needed, call the TTN Help line at (919) 541–5384.

II. Background Information

A. What Is the Statutory Authority for the Proposed Amendments?

New source performance standards (NSPS) implement CAA section 111(b), and are issued for categories of sources which cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.

Section 111 of the CAA requires that NSPS reflect the 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).

The current standards for steam generating units are contained in the NSPS for electric utility steam generating units (40 CFR part 60, subpart Da), industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db), and small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc).

The NSPS for electric utility steam generating units (40 CFR part 60, subpart Da) were originally promulgated on June 11, 1979 (44 FR 33580) and apply to units capable of firing more than 73 megawatts (MW) (250 million British thermal units per hour(MMBtu/hr)) heat input of fossil fuel that commenced construction, reconstruction, or modification after September 18, 1978. The NSPS also apply to industrial-commercial-institutional cogeneration units that sell more than 25 MW and more than one-third of their potential output capacity to any utility power distribution system. The most recent amendments to emission standards under subpart Da, 40 CFR part 60, were promulgated in 1998 (63 FR 49442) resulting in new NO_X limitations for subpart Da, 40 CFR part 60, units. Furthermore, in the 1998 amendments, we incorporated the use of output-based emission limits.

The NSPS for industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db) apply to units for which construction, modification, or reconstruction commenced after June 19, 1984 that have a heat input capacity greater than 29 MW (100 MMBtu/hr). Those standards were originally promulgated on November 25, 1986 (51 FR 42768) and also have been amended since the original promulgation to reflect changes in BDT for these sources. The most recent amendments to emission standards under subpart Db, 40 CFR part 60, were promulgated in 1998 (63 FR 49442) resulting in new NO_X limitations for subpart Db, 40 CFR part 60, units.

The NSPS for small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc) were originally promulgated on September 12, 1990 (55 FR 37674) and apply to units with a maximum heat input capacity greater than or equal to 2.9 MW (10 MMBtu/hr) but less than 29 MW (100 MMBtu/hr). Those standards apply to units that commenced construction, reconstruction, or modification after June 9, 1989.

Section 111(b)(1)(B) of the CAA requires the EPA periodically to review and revise the standards of performance, as necessary, to reflect improvements in methods for reducing emissions.

B. What Is the Role of the NSPS Program?

The NSPS program is one part of the CAA's integrated air quality management program. The primary purpose of the NSPS are to achieve long-term emissions reductions by ensuring that the best demonstrated emission control technologies are installed as the industrial infrastructure is modernized. Since 1970, the NSPS have been successful in achieving long-term emissions reductions at numerous industries by assuring cost-effective controls are installed on new, reconstructed, or modified sources. Recently, however, with the rapid advance of control technologies, the case-by-case new source review (NSR) permitting program has required greater emissions reductions than required by the NSPS, particularly for utility boilers. The existing and proposed market-based cap and trade programs require greater overall emissions reductions from the entire utility industry than the technology-based emission limits of the NSPS can achieve by regulating individual new sources.

Utility steam generators are subject to the current cap and trade programs for acid rain, which imposes a national cap on annual utility SO_2 emissions, and for interstate transport of ozone, which imposes a regional cap on summer time utility NO_X emissions in the eastern United States. The Administration's proposed Clear Skies Act would impose three trading programs: a national SO_2 trading program tighter than the acid rain trading program and two annual NO_X trading programs (one for the eastern United States and one for the remaining part of the country). Alternatively, EPA's Clean Air Interstate Rule (CAIR) proposes two new trading programs for utility steam generators to further control SO_2 and NO_X emissions in the eastern United States to reduce the transport of fine particulate matter and ozone.

Under these types of cap and trade programs, emissions of the regulated pollutants from all the regulated units are capped at a prescribed level (tons per year). Each affected unit is allocated a number of emission allowances, each of which conveys the right to emit a certain amount of the regulated pollutant. The total number of allowances allocated for any given year equals the emissions cap for that year. Each year, an affected unit must turn in a number of allowances equal to its emissions. Allowances can be bought and sold. Therefore, units can comply either by emitting equal to or less than permitted by the number of allowances they have been allocated or by obtaining additional allowances. This provides units with low cost reduction opportunities an incentive to reduce emissions below their allocated levels and allows units that face high costs for emissions reductions the opportunity to obtain allowances.

It is useful to understand the relationship between the NSPS program as it applies to utility steam generators and the various cap and trade programs being implemented or under development. First, the cap and trade program provides an incentive to apply modern emission controls on new sources because installing controls on a new unit is generally less expensive than installing similar controls on an existing unit. Minimizing emissions from a new source minimizes the allowances it must purchase (if no allowances are set aside for new sources) or may even allow it to sell allowances (if allowances are automatically allocated to new sources). Therefore, for source categories and pollutants subject to a stringent industry-wide emissions cap, a stringent NSPS is less important because new sources already have an economic incentive to install state-of-the-art controls. Second, over time, as technology improves, a cap continues to provide an incentive to install better technology, especially on new sources. In contrast, NSPS that are reviewed and amended every 8 years are unlikely to keep pace with technological improvements. Since the normal rulemaking process takes several years, more frequent updating of NSPS are impractical.

Finally, for sources and pollutants subject to a tight industry-wide emissions cap, stringent NSPS would have little or no effect on overall emissions in the geographic area regulated by the cap. Even if there were source specific reasons which result in it not making economic sense to install as effective emission controls as would be required under a stringent NSPS, that unit would have to use more allowances. This would result in fewer allowances being available for existing units, which would result in fewer emissions from existing sources. Therefore, for the pollutants, geographic area, and sources regulated by cap and trade programs, tighter NSPS would not necessarily affect total emissions. However, the stringency of the NSPS could affect the cost of achieving these emissions reductions. A cap and trade program allows the market to determine the most cost-effective way to achieve the overall emissions reductions goal. Installing modern controls on new sources will be the most cost-effective choice for most new sources. If there are circumstances where this is not the case, then overly stringent NSPS could limit a new source from using the most cost-effective controls for meeting its allocated portion of the emissions cap, thereby raising the cost of controls without necessarily increasing the environmental benefit.

The primary environmental benefit from the proposed amendments to the utility NSPS would come from the reduction of direct PM emissions, because direct emissions of PM are not subject to a cap and trade program (nor has such a program been proposed). For SO_2 (which is subject to a national trading program), the primary effect of the proposed amendments would be to establish the minimum control requirements for any steam generating units that are not subject to NSR. For NO_X, the same would be true nationally if Clear Skies were to pass or would be true in the eastern United States if CAIR is promulgated. Also, replacing the percent reduction requirement for SO_2 with an emission limit would harmonize the NSPS with the cap and trade programs by providing sources more flexibility in reducing emissions from new sources to meet the cap, while maintaining the same aggregate emissions.

III. Summary of the Proposed Amendments

The proposed amendments would amend the emission limits for SO_2, NO_X, and PM from steam generating units in subpart Da, 40 CFR part 60, (Electric Utility Steam Generating Units), and the PM emission limit for subpart Db, 40 CFR part 60, (Industrial-Commercial-Institutional Steam Generating Units), and subpart Dc, 40 CFR part 60, (Small Industrial-Commercial-Institutional Steam Generating Units). Only those units that begin construction, modification, or reconstruction after February 28, 2005, would be affected by the proposed amendments. Steam generating units subject to the proposed amendments but for which construction, modification, or reconstruction began on or before February 28, 2005, would continue to comply with the applicable standards under the current NSPS. Compliance with the proposed emission limits would be determined using the same testing, monitoring, and other compliance provisions set forth in the existing standards. In addition to amending the emission limits, we also are proposing several technical clarifications and corrections to existing provisions of the existing amendments, as explained below.

We are proposing language to clarify the applicability of subparts Da, Db, and Dc of 40 CFR part 60 to combined cycle power plants. Heat recovery steam generators that are associated with combined cycle gas turbines burning natural gas or a fuel other than synthetic-coal gas would not be subject to subparts Da, Db, or Dc, 40 CFR part 60, if the unit meets the applicability requirements of subpart KKKK, 40 CFR part 60 (Standards of Performance for Stationary Combustion Turbines). Subpart Da, Db, or Dc of 40 CFR part 60 would apply to a combined cycle gas turbine that burns synthetic-coal gas (*e.g.*, integrated coal gasification combine cycle power plants) and meets the applicability criteria of one of the proposed amendments, respectively.

We are proposing amendments to the definitions for boiler operating day, coal, coal-derived fuels, oil, and natural gas. The purpose of the proposed amendments is to clarify definitions across the three subparts and to incorporate the most current applicable American Society for Testing and Materials (ASTM) testing method references. Also, we are proposing to clarify the definition of an ‘‘electric utility steam generating unit’’ as applied to cogeneration units.

We are proposing several amendments to the provisions of the existing rule related to the use of continuous emission monitoring systems (CEMS) to obtain SO_2 and NO_X emission data for determining compliance with the rule requirements. The proposed amendments would eliminate duplicative or conflicting CEMS requirements for utility steam generating units that are subject to both 40 CFR part 60 and 40 CFR part 75 (acid rain).

A. What Are the Requirements for New Electric Utility Steam Generating Units (40 CFR Part 60, Subpart Da)?

The proposed PM emission limit for electric utility steam generating units is 6.4 nanograms per joule (ng/J) (0.015 lb/MMBtu) heat input regardless of the type of fuel burned. Compliance with this emission limit would be determined using the same testing, monitoring, and other compliance provisions for PM standards set forth in the existing rule.

The proposed SO_2 emission limit for electric utility steam generating units is 250 ng/J (2.0 pound per megawatt hour (lb/MWh)) gross energy output regardless of the type of fuel burned with one exception. The proposed SO_2 emission limit for electric utility steam generating units that burn over 90 percent coal refuse is 300 ng/J (2.4 lb SO_2/MWh) gross energy output. Under the existing subpart Da of 40 CFR part 60, coal refuse is defined as waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.*, culm, gob) containing coal, matrix material, clay, and other organic and inorganic material. Compliance with the proposed SO_2 emission limits would be determined on a 30-day rolling average basis using a CEMS to measure SO_2 emissions as discharged to the atmosphere and following the compliance provisions in the existing rule for the output-based NO_X standards applicable to new sources that were built after July 9, 1997.

The proposed NO_X emission limit for electric utility steam generating units is 130 ng/J (1.0 lb NO_X/MWh) gross energy output regardless of the type of fuel burned in the unit. Compliance with this emission limit would be determined on a 30-day rolling average basis using the testing, monitoring, and other compliance provisions in the existing rule for the output-based NO_X standards applicable to new sources that were built after July 9, 1997.

B. What Are the Requirements for Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60, Subpart Db)?

The proposed PM emission limit for industrial-commercial-institutional steam generating units is 13 ng/J (0.03 lb/MMBtu heat input) for units that burn coal, oil, wood, or a mixture of these fuels with other fuels. This limit would apply to units larger than 29 MW (100 million British thermal units per hour).

C. What Are the Requirements for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60, Subpart Dc)?

The proposed PM emission limit for small industrial-commercial-institutional steam generating units is 13 ng/J (0.03 lb/MMBtu heat input) for units that burn coal, oil, wood, or a mixture of these fuels with other fuels. This limit would apply to units between 8.7 MW and 29 MW (30 to 100 million Btu per hour).

IV. Rationale for the Proposed Amendments

A. What Is the Performance of Control Technologies for Steam Generating Units?

Control technologies for steam generating units are based on either pre-combustion controls, combustion controls, or post-combustion controls. Pre-combustion controls remove contaminants from the fuel before it is burned, and combustion controls reduce the amount of pollutants formed during combustion. Post-combustion controls remove pollutants formed from the flue gases before the gases are released to the atmosphere.

Selecting control technologies to reduce emissions of PM, SO_2, and NO_X from a new steam generating unit is a function of the type of fuel burned in the unit, the size of the unit, and other site-specific factors (*e.g.*, type of unit, firing and loading practices used, regional and local air quality requirements). All new steam generating units incorporate control technologies to reduce NO_X emissions. Natural gas is a gaseous fuel composed of methane and other hydrocarbons with trace amounts of sulfur and no ash. Accordingly, PM and SO_2 emissions from steam generating units firing natural gas are inherently low and generally do not require the use of additional PM or SO_2 control technologies. For new steam generating units firing fuel oils, PM and SO_2 controls may be required depending on the grade and composition of the fuel oil being burned in the unit. New steam generating units firing coal use PM and SO_2 controls.

1. PM Control Technologies

Filterable PM emissions from a steam generating unit are predominately fly ash and carbon. Carbon particles are generated from incomplete combustion of the fuel, and fly ash from burning fuels containing ash materials (the mineral and other incombustible matter portion of a fuel). These incombustible solid materials are released during the combustion process and are entrained in the flue gases. Distillate oils contain insignificant levels of ash, but residual fuel oils have higher ash contents, up to 0.5 percent. While different ranks of coals vary in ash content, all coals contain significant quantities of ash. The percentage of ash in a given coal can vary from less than 5 percent to greater than 20 percent depending on the coal source and level of coal cleaning.

Control of PM emissions from steam generating units relies on the use of post-combustion controls to remove solid particles from the flue gases. Electrostatic precipitators (ESP) and fabric filters (also called baghouses) are the predominant technologies used to control PM from coal-fired steam generating units. Either of these PM control technologies can be designed to achieve overall PM collection efficiencies in excess of 99.9 percent. Control of PM emissions from oil-fired steam generating units can be achieved by using oil burner designs with improved atomization and fuel mixing characteristics, by implementing better maintenance practices, and by using an ESP.

Electrostatic Precipitator. An ESP operates by imparting an electrical charge to incoming particles, and then attracting the particles to oppositely charged metal plates for collection. Periodically, the particles collected on the plates are dislodged in sheets or agglomerates (by rapping the plates) and fall into a collection hopper. The fly ash collected in the ESP hopper is a solid waste that is either recycled for industrial use or disposed of in a landfill.

The effectiveness of particle capture in an ESP depends primarily on the electrical resistivity of the particles being collected. The size requirement for an ESP increases with increasing coal ash resistivity. Resistivity of coal fly ash can be lowered by conditioning the particles upstream of the ESP with sulfur trioxide, sulfuric acid, water, or sodium. In addition, collection efficiency is not uniform for all particle sizes. Collection efficiencies greater than 99.9 percent, however, are achievable for small particles (less than 0.1 micrometer (μm)) and large particles (greater than 10 μm). Collection efficiencies achieved by ESP for the portion of particles having sizes between 0.1 μm and 10 μm tend to be lower.

Fabric Filters. A fabric filter collects PM in the flue gases by passing the gases through a porous fabric material. The buildup of solid particles on the fabric surface forms a thin, porous layer of solids, which further acts as a filtration medium. Gases pass through this cake/fabric filter, and all but the finest-sized particles are trapped on the cake surface. Collection efficiencies of fabric filters can be as high as 99.99 percent.

A fabric filter must be designed and operated carefully to ensure that the bags inside the collector are not damaged or destroyed by adverse operating conditions. The fabric material must be compatible with the gas stream temperatures and chemical composition. Because of the temperature limitations of the available bag fabrics, location of a fabric filter for use by a coal-fired electric steam generating unit is restricted to locations downstream of the air heater.

2. SO_2 Control Technologies

During combustion, sulfur compounds present in a fuel are predominately oxidized to gaseous SO_2. A small portion of the SO_2 oxidizes further to sulfur trioxide (SO_3). One approach to controlling SO_2 emissions from steam generating units is to limit the maximum sulfur content in the fuel. This can be accomplished by burning a fuel that naturally contains low amounts of sulfur or a fuel that has been pre-treated to remove sulfur from the fuel. A second approach is use a post-combustion control technology that removes SO_2 from the flue gases. These technologies rely on either absorption or adsorption processes that react SO_2 with lime, limestone, or another alkaline material to form an aqueous or solid sulfur by-product.

Coal Pre-Treatment. Sulfur in coal occurs as either inorganic sulfur or organic sulfur that is chemically bonded with carbon. Pyrite is the most common form of inorganic sulfur. There are two ways to pre-treat coal before combustion to lower sulfur emissions: Physical coal cleaning and gasification. Physical cleaning removes between 20 to 90 percent of pyritic sulfur, but is not effective at removing organic sulfur. The amount of pyritic sulfur varies with different coal types, but it is typically half of the total sulfur for high sulfur coals.

Coal gasification breaks coal apart into its chemical constituents (typically a mixture of carbon monoxide, hydrogen, and other gaseous compounds) prior to combustion. The product gas is then cleaned of contaminants prior to combustion. Gasification reduces SO_2 emissions by over 99 percent.

Alkali Wet Scrubbing. The SO_2 in a flue gas can be removed by reacting the sulfur compounds with a solution of water and an alkaline chemical to form insoluble salts that are removed in the scrubber effluent. The most commonly used wet flue gas desulfurization (FGD) systems for coal-fired steam generating units are based on using either limestone or lime as the alkaline source. In a wet scrubber, the flue gas enters a large vessel located downstream of the particle control device where it contacts the lime or limestone slurry. The calcium in the slurry reacts with the SO_2 to form reaction products that are predominately calcium sulfite. Because of its high alkalinity, fly ash is sometimes mixed with the limestone or lime. Other alkaline solutions can be used for scrubbing including sodium carbonate, magnesium oxide, and dual alkali.

The SO_2 removal efficiency that a wet FGD system can achieve for a specific steam generating unit is affected by the sulfur content of the fuel burned, which determines the amount of SO_2 entering the wet scrubber, and site-specific scrubber design parameters including liquid-to-gas ratio, pH of the scrubbing medium, and the ratio of the alkaline sorbent to SO_2. Annual SO_2 removal efficiencies have been demonstrated above 98 percent. Advanced wet scrubber designs include limestone scrubbing with forced oxidation (LSFO) and magnesium enhanced lime scrubbing FGD systems.

Limestone Scrubbing with Forced Oxidation. Limestone scrubbing with forced oxidation is a variation of the wet scrubber described above and can use either limestone or magnesium enhanced lime. In the LSFO process, the calcium sulfite initially formed in the spray tower absorber is oxidized to form gypsum (calcium sulfate) by bubbling compressed air through the sulfite slurry. The resulting gypsum by-product has commercial value and can be sold to wallboard manufacturers. Also, because of their larger size and structure, gypsum crystals settle and dewater better than calcium sulfite crystals, reducing the required size of by-product handling equipment. The high gypsum content also permits disposal of the dewatered waste without fixation.

Spray Dryer Adsorption. An alternative to using wet scrubbers is to use spray dryer adsorber technology. A spray dryer adsorber operates by the same principle as wet lime scrubbing, except that instead of a bulk liquid (as in wet scrubbing) the flue gas containing SO_2 is contacted with fine spray droplets of hydrated lime slurry in a spray dryer vessel. This vessel is located downstream of the air heater outlet where the gas temperatures are in the range of 120 °C to 180 °C (250 °F to 350 °F). The SO_2 is absorbed in the slurry and reacts with the hydrated lime reagent to form solid calcium sulfite and calcium sulfate. The water is evaporated by the hot flue gases and forms dry, solid particles containing the reacted sulfur. Most of the SO_2 removal occurs in the spray dryer vessel itself, although some additional SO_2 capture has also been observed in downstream particulate collection devices. This process produces a dry waste product, which is mostly disposed of in a landfill.

The primary operating parameters affecting SO_2 removal are the calcium-reagent-to-sulfur stoichiometric ratio and the approach to saturation in the spray dryer. To decrease sorbent costs, a portion of the solids collected in the spray dryer and the PM collection device may be recycled to the spray dryer. The SO_2 removal efficiencies of new lime spray dryer systems are generally greater than 90 percent.

Dry Injection. For the dry injection process, dry hydrated or slaked lime (or another suitable sorbent) is directly injected into the ductwork or boiler upstream of a PM control device. Some systems use spray humidification followed by dry injection. The SO_2 is adsorbed and reacts with the powdered sorbent. The dry solids are entrained in the combustion gas stream, along with fly ash, and then collected by the downstream PM control device.

The dry injection process produces a dry, solid by-product that is easier to dispose. However, the SO_2 removal efficiencies for existing dry injection systems are lower than for the other FGD technologies ranging from approximately 40 to 60 percent when using lime or limestone, and up to 90 percent using other sorbants (*e.g.*, sodium bicarbonate).

Fluidized-bed Combustion with Limestone. One of the appealing features of selecting a steam generating unit that uses a fluidized-bed combustor (FBC) is the capability to control SO_2 emissions during the combustion process. This is accomplished by adding finely crushed limestone along with the coal (or other solid fuel) to the fluidized bed. During combustion, calcination of the limestone (reduction to lime by subjecting to heat) occurs simultaneously with the oxidation of sulfur in the coal to form SO_2. The SO_2, in the presence of excess oxygen, reacts with the lime particles to form calcium sulfate. The sulfated lime particles are removed with the bottom ash or collected with the fly ash by a downstream PM control device (for most existing FBC steam generating unit applications, a fabric filter is used as the PM control device). Fresh limestone is continuously fed to the bed to replace the reacted limestone. The SO_2 removal efficiencies for some FBC units are in the range of approximately 80 to 98 percent.

3. NO_X Control Technologies

Nitrogen oxides are formed in a steam generating unit by the oxidation of molecular nitrogen in the combustion air and any nitrogen compounds contained in the fuel. The formation of NO_X from nitrogen in the combustion air is dependent on two conditions occurring simultaneously in the unit's combustion zone: high temperature and an excess of combustion air. Under these conditions, significant quantities of NO_X are formed regardless of the fuel type burned. New steam generating units being installed today in the United States routinely include burners and other features designed to reduce the amounts of NO_X formed during combustion.

Beyond the lower levels of NO_X emissions achieved using combustion controls, additional NO_X emission control can be achieved for steam generating units by installing post-combustion control technologies. These technologies involve converting the NO_X in the flue gas to molecular nitrogen (N2) and water using either a process that requires a catalyst (called selective catalytic reduction (SCR)) or a process that does not use a catalyst (called selective noncatalytic reduction (SNCR)). Both SCR and SNCR technologies have been applied widely to gas-, oil-, and coal-fired steam generating units.

NO_X Combustion Controls. Combustion controls reduce NO_X emission formation by controlling the peak flame temperature and excess air in and around the combustion zone through staged combustion. With staged combustion, the primary combustion zone is fired with most of the air needed for complete combustion of the fuel. The remaining air is introduced into the products of the partial combustion in a second combustion zone. Air staging lowers the peak flame temperature, thereby reducing thermal NO_X, and reduces the production of fuel NO_X by reducing the oxygen available for combination with the fuel nitrogen. Staged combustion may be achieved internally in the fuel burners using specially designed burner configurations (often referred to as low-NO_X burners), or external to the burners by diverting a portion of the combustion air from the burners and introducing it through separate ports and/or nozzles, mounted above the burners (often referred to as overfire air (OFA)). The actual NO_X reduction achieved with a given NO_X combustion control technology varies from unit to unit. Use of low-NO_X burners can reduce NO_X emissions by approximately 35 to 55 percent. Use of OFA reduces NO_X emissions levels in the range of 15 to 30 percent. Higher NO_X emissions reductions are achieved when combustion control technologies are combined (*e.g.*, combining OFA with low-NO_X burners can achieve NO_X emissions reductions in the range of 60 percent).

Other NO_X combustion control techniques include reburning, co-firing natural gas, and flue gas recirculating. In reburning, coal, oil, or natural gas is injected above the primary combustion zone to create a fuel rich zone to reduce burner-generated NO_X to N2 and water vapor. Overfire air is added above the reburning zone to complete combustion of the reburning fuel. Natural gas co-firing consists of injecting and combusting natural gas near or concurrently with the main oil or coal fuel. Flue gas recirculating decreases combustion temperatures by mixing flue gases with the incoming combustion air. For gas and oil units, flue gas recirculating can reduce NO_X emissions by 75 percent.

SCR Technology. The SCR process uses a catalyst with ammonia (NH_3) to reduce the nitrogen oxide (NO) and nitrogen dioxide (NO_2) in the flue gas to molecular nitrogen and water. Ammonia is diluted with air or steam, and this mixture is injected into the flue gas upstream of a metal catalyst bed that typically is composed of vanadium, titanium, platinum, or zeolite. The SCR catalyst bed reactor is usually located between the economizer outlet and air heater inlet, where temperatures range from 230 °C to 400 °C (450 °F to 750 °F). The SCR technology is capable of NO_X reduction efficiencies of 90 percent or higher.

SNCR Technology. A SNCR process is based on the same basic chemistry of reducing the NO and NO2 in the flue gas to molecular nitrogen and water, but does not require the use of a catalyst to promote these reactions. Instead, the reducing agent is injected into the flue gas stream at a point where the flue gas temperature is within a specific temperature range of 870 °C to 1,090 °C (1,600 °F to 2,000 °F). Currently, two SNCR processes are commercially available; one uses ammonia as the reagent, and the other process uses an aqueous urea solution in place of ammonia. The NO_X reduction levels for SNCR are in the range of approximately 30 to 50 percent.

B. Regulatory Approach

We have reviewed emission data and control technology information applicable to criteria pollutants and have concluded that the regulation of NO_X, PM, and SO_2 emissions from these sources under the NSPS is appropriate. The proposed amendments to the NSPS reflect the BDT for these sources based on the performance and cost of the emission control technologies discussed above. In amending the emission limits based on BDT, we have incorporated a fuel-neutral concept and, to the extent that it is practical and reasonable, output-based emission limits. These approaches provide the level of emission limitation required by the CAA for the NSPS program and achieve additional benefits of compliance flexibility, increased efficiency, and the use of cleaner fuels.

1. Fuel-Neutral Approach

We are proposing to amend emission limits using a fuel-neutral approach in most cases. This approach is currently used for the NO_X emission standards under subparts Da and Db of 40 CFR part 60 and encourages pollution prevention by recognizing the environmental benefits of combustion controls based on the use of clean fuels. The fuel-neutral approach provides a single emission limit for steam generating units based on BDT without regard to specific type of steam generating equipment or fuel type. This approach provides an incentive to facilities to consider fuel use, boiler type, and control technology when developing an emission control strategy. Therefore, owners and operators of affected sources are able to use the most effective combination of add-on control technologies, clean fuels, and boiler design to meet the emission limit. For example, an owner and operator may decide that the blending of a low sulfur fuel with coal or physically washing the coal in combination with dry-injection technology would be a more cost-effective way of meeting the NSPS than burning a higher sulfur coal and installing a FGD system. Alternatively, if a source does not have long-term access to clean fuels at a reasonable cost, then emission control technology is available to allow units to burn higher sulfur fuels and still comply with the emission limits.

To develop a fuel-neutral emission limit, we analyzed emission control performance from coal-fired units to establish an emission level that represents BDT. The higher sulfur, nitrogen, and ash contents for coal compared to oil or gas makes application of BDT to coal-fired units more complex than application to either oil-or gas-fired units. Therefore, emission levels selected for coal-fired steam generating units using BDT would be achievable by oil- and gas-fired electric utility steam generating units. The resulting emission levels from coal-fired units would apply to all boiler types and fuel use combinations. It is appropriate for all fuels to have the same limits to avoid discouraging the use of cleaner fuels. The BDT analysis was conducted separately for 40 CFR part 60, subparts Da, Db, and Dc.

2. Output-Based Emission Standards

We have established pollution prevention as one of our highest priorities. One of the opportunities for pollution prevention is maximizing the efficiency of energy generation. An output-based standard establishes emission limits in a format that incorporates the effects of unit efficiency by relating emissions to the amount of useful-energy generated, not the amount of fuel burned. By relating emission limitations to the productive output of the process, output-based emission limits encourage energy efficiency because any increase in overall energy efficiency results in a lower emission rate. Allowing energy efficiency as a pollution control measure provides regulated sources with an additional compliance option that can lead to reduced compliance costs as well as lower emissions. The use of more efficient technologies reduces fossil fuel use and leads to multi-media reductions in environmental impacts both on-site and off-site. On-site benefits include lower emissions of all products of combustion, including hazardous air pollutants, as well as reducing any solid waste and wastewater discharges. Off-site benefits include the reduction of emissions and non-air environmental impacts from the production, processing, and transportation of fuels.

While output-based emission limits have been used for regulating many industries, input-based emission limits have been the traditional method to regulate steam generating units. However, this trend is changing as we seek to promote pollution prevention and provide more compliance flexibility to combustion sources. For example, in 1998 we amended the NSPS for electric utility steam generating units (40 CFR part 60, subpart Da) to use output-based standards for NO_X (40 CFR 63.44a, 62 FR 36954, and 63 FR 49446). In this action, we are proposing output-based emission limits for SO_2 and NO_X under subpart Da of 40 CFR part 60. The format of the proposed output-based limits is mass of pollutant per megawatt hour of gross energy output. We are proposing to base the limits on gross energy output because of the monitoring difficulties in measuring net output. The current output-based emission limit for NO_X in subpart Da of 40 CFR part 60 is based on gross energy output. The difficulties of monitoring net energy output are explained in the preamble to the 1998 NO_X amendment for subpart Da of 40 CFR part 60 (63 FR 49448).

Electrical Generating Units. For subpart Da of 40 CFR part 60, we are proposing amendments which establish output-based emission limits for SO_2 and NO_X. For PM, we are proposing an amended input-based emission limit and requesting comments on an output-based limit. The proposed output-based emission limit for SO_2 will replace both the current percentage reduction requirement and input-based emission limit.

Industrial-Commercial-Institutional Units. For subpart Db of 40 CFR part 60, we are soliciting comment on an optional output-based NO_X emission limit for units that generate electricity. Units that generate electricity have the greatest opportunity for achieving increases in energy efficiency. We would structure the output-based limit as an option because we determined that for some applications of industrial, commercial, and institutional boilers, the monitoring, recordkeeping, and reporting costs for demonstrating compliance with output-based emission limits would be unreasonable.

Determining compliance with an output-based emission limit requires the use of a CEMS. Specifically, emission data must be collected in units of pounds per hour to calculate an output-based emission rate. The CEMS currently required by subpart Db of 40 CFR part 60, do not provide that data. A CEMS also would need to collect continuous exhaust flow data to calculate emissions in units of pounds per hour. Additionally, continuous energy monitoring devices would be needed to comply with an output-based limit. Not all electric generating units subject to subpart Db of 40 CFR part 60 may be designed with these monitoring systems. Due to costs, we are not expanding the monitoring requirements under subpart Db of 40 CFR part 60 to require the collection of exhaust flow and electrical generation data, and we are not proposing an output-based emission limit for subpart Db of 40 CFR part 60. Instead, we are proposing that individual facilities be given the option of complying with either the current input-based or an equivalent output-based limit.

Output-based limits may be feasible for NO_X at units that operate continuous emission flow and electrical generation monitoring equipment. For example, some industrial-commercial-institutional electric generating units may be required to install continuous exhaust flow monitoring systems to demonstrate compliance with State regulatory programs, such as NO_X requirements in State implementation plans. Where the required monitors are in place, an output-based emission limit provides an incentive for increased energy efficiency and the use of highly efficient technologies like combined heat and power systems (next section).

The use of output-based emission limits is less feasible for PM because current regulations generally do not require industrial-commercial-institutional steam generators to operate PM CEMS. Furthermore, the percent removal format for SO_2 contained in subpart Db of 40 CFR part 60 is not compatible with an output-based standard.

3. Combined Heat and Power

Combined heat and power (CHP) is the sequential generation of power (electricity or shaft power) and thermal energy from a common combustion source. The application of CHP captures and uses much of the waste heat that ordinarily is discarded from conventional electrical generation, where two-thirds of the input energy typically becomes waste heat (through exhaust stacks and cooling towers). In a CHP system, this captured energy can be used to provide process heat and space cooling or heating. By recovering waste heat, CHP systems achieve much higher fuel efficiencies than separate electric and thermal generators, and emit less pollution. Using CHP is a method for industry not only to decrease criteria pollutants and hazardous air pollutants, but also to move forward on addressing concerns about increasing levels of heat trapping gases in the atmosphere.

Because CHP units produce both electrical and thermal energy, the proposed amendments must account for both types of energy in demonstrating compliance with an output-based emission limit. Energy output for CHP units is the sum of gross electrical output and the useful energy of the process steam. For the output-based emission limits currently contained in subpart Da of 40 CFR part 60, we defined the useful energy of the process steam from CHP units as 50 percent of the thermal output. We chose the 50 percent allowance at that time because using an allowance as if the steam would be converted to electricity (up to 38 percent efficiency) would not account for the environmental benefits of CHP applications, and allowing 100 percent could potentially overstate the environmental benefits of CHP applications. Additionally, this approach to CHP units was consistent with a Federal Energy Regulatory Commission (FERC) regulation determining the efficiency of CHP units.

In the proposed amendments, we are soliciting comments on the appropriateness of giving more than 50 percent credit for thermal output, and on a different approach to account for the thermal energy from CHP units. The proposed approach would account for the efficiency benefits of the thermal output based on the amount of avoided emissions that a conventional boiler system would otherwise emit had it provided the same thermal output as the CHP system. The avoided emissions would be determined for each unit based on individual unit operating factors. The proposed compliance procedures for CHP units follow this logic:

(1) Determine the emission rate of the combustion source that provides energy to the CHP unit (in units of pounds per hour) from the continuous emission and flow monitoring system;

(2) Calculate the avoided emissions (in units of pounds per hour) for the amount of thermal energy generated from the CHP unit; and

(3) Subtract the avoided emissions from the total emissions of the CHP unit and divide that value by the gross electrical output of the CHP unit.

This approach more accurately reflects the environmental benefits of CHP units and accounts for site-specific differences in system design, operation, and various power-to-heat ratios (the ratio of gross electrical energy generation to useful thermal energy generation).

If a CHP unit demonstrates compliance with the output-based emission limit, an output-based emission rate would be calculated based on the following equation:

$$Echp = [Et - THa]/Oe \qquad \text{(Eq. 1)}$$

Where:

Echp = CHP emission rate (lb/MWh)
Et = total emissions (pounds per hour (lb/hr))
THa = avoided thermal emissions (lb/hr)
Oe = electrical output (MW)

The avoided thermal emissions (A) would be calculated based on the following equation:

$$A = [E/0.8] * Oth \qquad \text{(Eq. 2)}$$

Where:

A = avoided thermal emissions (lb/hr)
E = applicable NSPS emission limit for the displaced boiler (pound per million British thermal units heat input (lb/MMBtu))
0.8 = assumed boiler efficiency (percent)
Oth = thermal output (MMBtu/hr)

Under this approach, the avoided emission rate for the displaced steam generating capacity would be calculated using the input-based 40 CFR part 60, subpart Db, NSPS emission limit applicable to the steam generating unit. This is appropriate since, in the absence of the CHP facility, the thermal energy would be provided by a new boiler subject to 40 CFR part 60, subpart Db. The NSPS limit would be converted from an input- to a thermal output-based emission rate by dividing the input-based emission limit by an assumed thermal system efficiency of 80 percent. We have chosen a boiler thermal efficiency of 80 percent because it is considered reasonable and takes into consideration all fuels and a variety of design configurations used for boilers in CHP facilities. Then, the avoided emission rate is converted to units of pounds per hour by multiplying by the recovered useful thermal output of the CHP system. We are soliciting comments both on this approach and other methods of determining displaced thermal emissions besides a boiler subject to 40 CFR part 60, subpart Db.

C. How Did EPA Determine the Amended Standards for Electric Utility Steam Generating Units (40 CFR Part 60, Subpart Da)?

New source performance standards for electric utility steam generating units in the proposed amendments would apply only to affected sources that begin construction, modification, or reconstruction after February 28, 2005. As discussed earlier in this preamble, the regulatory approach we are using to develop the proposed standards is based on our determination of BDT for control of PM, SO_2, and NO_X from electric utility steam generating units. Furthermore, we decided that the proposed standards should use a fuel-neutral and an output-based emission limit format, to the extent that it is practical and reasonable.

To set the proposed output-based standards at new plants, we used measured output-based emissions where available. When gross output information was unavailable, we selected emission limits based on heat input and used a gross electrical efficiency to determine the output-based standard. Recent technical publications assert that new supercritical plants will be able to achieve net efficiencies as high as 45 percent, and analysis of EPA's Clean Air Markets Division data indicates that the top 10 percent of utility units are presently operating at a gross efficiency of 38 percent or greater. However, to account for variations in boiler designs and to allow efficiency as a control technology, we selected 36 percent gross efficiency (top 25 percent of existing units) as our conversion factor. We are soliciting comments on this approach and the appropriateness of the selected value.

Only three new coal utility units have been built since the prior NSPS amendments in 1998. The plants are the Red Hills facility in Mississippi, the Hawthorn facility in Missouri, and the Northside facility in Florida. These plants are designed to burn lignite, subbituminous, and bituminous coal, respectively. To provide a broader set of data to base the proposed amendments on, we also analyzed older plants that have been retrofitted with controls.

1. Selection of the Proposed PM Standard

Direct particulate matter emissions from steam generating units firing coal result from the entrainment of fly ash in the flue gases and, to a lesser extent, from unburned fuel particles and downstream post-combustion reactions. Currently, 40 CFR part 60, subpart Da, limits PM emissions from electric utility steam generating units to 0.03 lb/MMBtu heat input regardless of the fuel burned in the unit.

Coal-fired electric utility steam generating units meeting the current PM emission limit under subpart Da, 40 CFR part 60, predominately use either a fabric filter or ESP to remove PM from the flue gases. Over the years, the performance of fabric filters and ESP installed on coal-fired steam generating units has improved as a result of advanced control device designs and other performance enhancements (*e.g.*, use of new bag materials for fabric filters and use of computer modeling and improved rapper and electrical system designs for ESP). We concluded that fabric filters and ESP represent BDT for continuous reduction of PM emissions from coal-fired electric utility steam generating units.

To assess performance levels achievable by fabric filters and ESP installed on new coal-fired electric utility steam generating units, we reviewed the permits of three recent facilities covered under subparts Da of 40 CFR part 60. The permit limits for the Hawthorn, Red Hills, and Northside facilities are 0.018, 0.015, and 0.011 lb PM/MMBtu heat input respectively. The Hawthorn limit includes condensible PM, and the facility is achieving filterable PM control of 0.012 lb/MMBtu. The Northside facility is achieving filterable PM control of 0.004 lb/MMBtu. Based on this information, we concluded that current fabric filter and ESP control technologies being installed on new electric utility steam generating units can achieve PM emission levels below the level of the existing PM standard, and that amending this PM standard for new electric utility steam generating units is warranted.

To select a level for the proposed PM standard, we evaluated the cost-effectiveness of two limits (0.018 lb PM/MMBtu and 0.015 lb PM/MMBtu) along with the ability of a broad range of coal types and boiler configurations to achieve the standard. The annual reduction and incremental cost of reducing PM emissions from the existing NSPS (0.03 lb/MMBtu) to 0.018 lb/MMBtu is 420 tons at an average incremental cost of $3,100/ton. The annual reduction and incremental cost of reducing the PM standard from 0.018 lb/MMBtu to 0.015 lb/MMBtu is 110 tons at an average incremental cost of $8,400/ton. We selected a level for the proposed standard considering the above performance information, non-air quality health effects, and effects on energy production associated with achieving these emission levels. The proposed PM standard is 6.5 ng/J (0.015 lb/MMBtu heat input). Based on information from the Department of Energy Cost and Quality of Fuels for Electric Utility Plants 2001, 75 percent of existing coal utility units would be able to comply with the proposed limit using either an ESP or fabric filter operating at a 99.8 percent collection efficiency, and 95 percent would be able to comply with either an ESP or fabric filter operating at a 99.9 percent collection efficiency. The remaining 5 percent would be able to comply with either a high efficiency ESP or fabric filter operating at a 99.95 percent collection efficiency or coal washing in conjunction with a less efficient PM control device. We are particularly interested in soliciting comments providing information to guide this determination. In the event data is presented indicating a more stringent standard is achievable, we would consider a 4.7 ng/J (0.011 lb/MMBtu heat input) standard. If data is presented demonstrating that this standard will pose significant technical difficulties for a range of fuels, we would consider a standard of 8.6 ng/J (0.02 lb/MMBtu heat input).

2. How Did EPA Select the Proposed SO_2 Standard?

The current SO_2 standard in 40 CFR part 60, subpart Da, uses a percent reduction format in conjunction with a maximum emission limit but provides an allowance for a lower percent reduction requirement if a target emission limit is demonstrated. Effectively, these standards require a new coal-fired steam generating unit to achieve a 90 percent reduction of the potential combustion concentration of SO_2 (*i.e.*, the theoretical amount of SO_2 that would be emitted in the absence of using any emission control systems), and meet an emission limit of 1.2 lb SO_2/MMBtu heat input. However, if a unit can demonstrate an SO_2 emission rate less than 0.6 lb/MMBtu heat input, then the unit is only required to achieve a 70 percent reduction.

As discussed earlier in this preamble, a number of SO_2 control technologies are currently available for use with new coal-fired electric utility steam generating units. The SO_2 control strategy used for a particular new electric utility steam generating unit project is fundamentally determined by the type of combustion technology that is selected for the new unit. Owners and operators building a new steam generating unit using integrated gasification combined cycle (IGCC) or fluidized-bed combustion technology generally use different control strategies than owners and operators building a new steam generating unit using pulverized coal combustion technology.

Another important factor influencing the selection of SO_2 control technology for a new unit is the sulfur content of the coals expected to be burned. According to the most recent Department of Energy data (FERC form–423 and form EIA–423), non-refuse coal-fired power plants in the United States had an average uncontrolled sulfur emissions potential of 1.8 lb SO_2/MMBtu heat input in 2002. Since 1995, eight new coal-fired electric utility steam generating units have been built in the United States, and these units have an average uncontrolled SO_2 emission level of 1.6 lb SO_2/MMBtu heat input and a maximum of 2.1 lb SO_2/MMBtu heat input. We concluded that new electric utility steam generating projects will use either IGCC technology, state-of-the-art SO_2 controls, or burn low- and medium-sulfur content coals to achieve reductions.

New steam generating projects that use IGCC technology will inherently have only trace SO_2 emissions because over 99 percent of the sulfur associated with the coal is removed by the coal-gasification process. New steam generating units that use fluidized-bed combustion technology can control SO_2 during the combustion process by coal washing, coal blending, adding limestone into the fluidized-bed, and installing polishing scrubbers. However, to date, application of fluidized-bed combustion technology has been limited to the lower end of the steam generating unit sizes expected for new electric utility projects (the largest FBC unit built to date is 350 MW). For SO_2 controls applied to steam generating units using pulverized coal combustion technology, control strategies involve the burning of low sulfur coals, coal washing, coal blending, the use of post-combustion controls to remove SO_2 from the flue gases, and co-firing with natural gas, low sulfur fuel oil, or biomass. The majority of new electric utility steam generating units will use pulverized coal combustion technology. Therefore, using the fuel-neutral approach discussed earlier, we decided to base the BDT determination for development of an amended SO_2 standard on application of SO_2 control technologies to pulverized coal-fired steam generating units.

We reviewed the SO_2 control technologies currently available for application to pulverized coal-fired electric utility steam generating units. We concluded that FGD is BDT for these units. The type of FGD system used for a given new unit depends on a number of site-specific factors, including unit size, sulfur content of coal to be burned in the unit, and the overall economics of each application.

Existing wet FGD systems used for pulverized coal-fired electric utility steam generating units, especially the scrubber technologies installed in the last 10 years, are capable of consistently achieving SO_2 removal efficiencies of 95 percent and higher. Multiple plants have demonstrated that this level of control is achievable on a long-term basis.

Enhanced wet FGD systems are capable of achieving high removal efficiencies and can be used for units burning the highest sulfur content coals. In addition, dry FGD technologies such as lime spray dryer (LSD) systems can be used to achieve significant reductions in SO_2 emissions under certain conditions. Typically, LSD systems have been used for smaller size electric utility steam generating units burning lower sulfur content coals. There are several LSD systems designed for 90 percent or higher SO_2 removal efficiencies. Based on this information, we concluded that current FGD systems being installed on new electric utility steam generating units can achieve SO_2 emission levels below the level of the existing SO_2 standard, and that amending this SO_2 standard for new electric utility steam generating units is warranted.

To assess the SO_2 control performance level of utility units, we reviewed new and retrofitted facilities with SO_2 controls. Since 1995, the Harrison coal-fired power plant in West Virginia has used a FGD system based on wet scrubbing technology that has achieved annual SO_2 emissions of approximately 1 lb/MWh gross output from an uncontrolled level of 5.4 lb/MMBtu heat input. Based on hourly acid rain data from 1997 to 2000, the highest 30-day average from the three stacks ranged between 1.3 to 1.5 lb SO_2/MWh gross output. The Conemaugh facility in Pennsylvania has maintained 30-day average emissions under 1.4 lb SO_2/MWh gross output over the same period using coal with uncontrolled emissions of 3.4 lb SO_2/MMBtu heat input. Based on the performance of the Harrison facility, we are selecting a single limit for all fuels of 0.21 lb SO_2/MMBtu heat input as the basis for the proposed standard. We realize many new units will operate below this value, but the proposed limit would allow the highest sulfur coals (uncontrolled emissions of 7 lb SO_2/MMBtu) to meet the limit using similar technology as the Harrison facility. Using a gross electrical generating efficiency of 36 percent, the proposed standard is 250 ng/J (2.0 lb/MWh) of SO_2. Based on the third quarter 2004 emissions data from EPA's Clean Air Markets Division, eleven percent of existing coal units are presently operating at or below this limit. We are soliciting comments on the proposed limit and are considering the range of 120 to 250 ng/J (0.9 to 2.0 lb/MWh) for the final rule.

Of the coals used in existing electric utility plants, 70 percent could comply with the proposed standard using spray dryers. Eighty nine percent could meet the standard with conventional wet FGD technology, and ninety nine percent with enhanced wet scrubbing. Only one percent of existing coal utilities use coal with uncontrolled SO_2 emissions greater than 7 lb/MMBtu. If a utility were to elect to use a fuel with uncontrolled SO_2 emissions above 7 lb/MMBtu heat input, technology is available that would allow the unit to meet the proposed standard. Options include physical coal washing, blending with low sulfur fuels, combining SO_2 control technologies like those applied at the JEA Northside facility, super-critical high-efficiency boilers, combined heat and power, and gasification. In addition, emerging SO_2 control technologies will allow the direct use of any fuel in a conventional coal plant without fuel blending or pretreatment. Therefore, regardless of the sulfur content of the bituminous, subbituminous, or lignite coal burned by a new electric utility steam generating unit, SO_2 emission control technologies are available that would allow the unit owner or operator to comply with the proposed SO_2 standard at a reasonable cost.

Coal refuse (also called waste coal) is a combustible material containing a significant amount of coal that is reclaimed from refuse piles remaining at the sites of past or abandoned coal mining operations. Coal refuse piles are an environmental concern because of acid seepage and leachate production, spontaneous combustion, and low soil fertility. Advancements in fluidized-bed combustion technology allow reclaimed coal refuse to be burned in power plants and cogeneration facilities. Facilities that burn coal refuse provide special multimedia environmental benefits by combining the production of energy with the clean up of coal refuse piles and by reclaiming land for productive use. Consequently, because of the unique environmental benefits that coal refuse-fired power plants provide, these units warrant special consideration so as to prevent the amended NSPS from discouraging the construction of future coal refuse-fired power plants in the United States.

We reviewed emissions data and title V permit information for the existing coal refuse-fired power plants currently operating in the United States. Based on our review, we concluded that the PM and NO_X emission levels for these facilities were comparable to the emission levels from other coal-fired electric utility power plants using similar control technology. Thus, coal refuse-fired electric utility steam generating units can achieve the same PM and NO_X emission standards being proposed for bituminous, subbituminous, and lignite coals. However, there is a possibility that coal refuse from some piles will have sulfur contents at such high levels that they present potential economic and technical difficulties in achieving the same SO_2 standard that we are proposing for higher quality coals. Therefore, so as not to preclude the development of these projects, we are proposing a separate SO_2 emission limit that we concluded is achievable for the full range of coal refuse piles remaining in the United States. The proposed standard is 0.25 lb SO_2/MMBtu heat input for facilities that burn over 90 percent coal refuse. Using the same baseline efficiency of 36 percent, the proposed standard is 300 ng/J (2.4 lb/MWh) of SO_2 for units that burn coal refuse. We are requesting comment on the proposed limit and are considering the range of 180 to 360 ng/J (1.4 to 2.8 lb/MWh) for the final rule.

3. How Did EPA Select the Proposed NO_X Standard?

In 1998, we amended the NO_X emission limits for new electric utility steam generating units built or reconstructed after July 9, 1997 (63 FR 49444, September 9, 1998). At that time, we concluded that SCR represented BDT for continuous reduction of NO_X emissions from electric utility steam generating units. The level of the amended NO_X emission limit was selected based on the performance data of SCR control technology in combination with combustion controls on coal-fired steam generating units. The existing NSPS is 200 ng/J of gross output (1.6 lb/MWh) for new units and 65 ng/J of heat input (0.15 lb/MMBtu) for reconstructed units (63 FR 49444).

We reviewed the NO_X control technologies currently available for application to electric utility steam generating units, and concluded that SCR remains BDT for continuous reduction of NO_X emissions from these sources. However, since the time we selected the current NO_X emission limits, the number of electric utility steam generating units in the United States using SCR control technology has substantially increased. In 2002, more than 50 electric utility steam generating units were operating SCR controls, with additional facilities installing or planning to install the technology. In addition, at units operating SCR controls, the installation of NO_X CEMS allows the collection of long-term data on SCR control performance. As a result, we now have access to significantly more data on the performance of SCR control technology than was available to us in 1998.

The design NO_X reduction efficiencies of the SCR controls in use on specific electric utility steam generating units vary depending on site-specific conditions (*e.g.*, retrofit to existing units versus new unit applications, facility's air permit requirements, other NO_X combustion controls used), but operating data indicate that NO_X emission reduction levels of 90 percent or more can consistently be achieved for coal-fired electric utility steam generating units.

Two units built after the 1998 NO_X NSPS amendments for utility units are the JEA Northside facility in Florida and the Hawthorn facility in Missouri. Both are operating within their permit limits of 0.09 lb NO_X/MMBtu heat input and 0.08 lb NO_X/MMBtu heat input, respectively. These values are below the current standard of 1.6 lb/MWh, which is based on 0.15 lb NO_X/MMBtu heat input. Based on the incorporation of combustion control technologies into new electric utility steam generating unit designs and the demonstrated SCR performance for recently built units, we concluded that amending this NO_X standard for new electric utility steam generating units is warranted.

While the WA Parish coal facility in Texas has demonstrated control of approximately 0.04 lb NO_X/MMBtu heat input, we are proposing a level of 0.11 lb/MMBtu heat input as the basis for the proposed standard. This emission limit allows for the possibility of using fluidized beds and advanced-combustion controls as an alternative to SNCR or SCR. Advanced combustion controls reduce compliance costs, parasitic energy requirements, and ammonia emissions. We converted this value to the corresponding value in units of lb/MWh using an overall efficiency factor of 36 percent. Therefore, we are proposing for the NO_X standard a level of 130 ng/J (1.0 lb/MWh) gross electricity output as determined on a 30-day rolling average. Based on third quarter 2004 emissions data from EPA's Clean Air Markets Division, approximately 14 percent of existing units are achieving this limit. We are soliciting comments on this approach and are particularly interested in additional data on the achievable NO_X levels of fluidized beds without additional NO_X controls and pulverized coal units with advanced combustion controls. The range of values we are presently considering for the final rule is 60 to 170 ng/J (0.47 to 1.3 lb/MWh).

D. How Did EPA Determine the Amended Standards for Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60, Subparts Db and Dc)?

New source performance standards for industrial-commercial-institutional steam generating units in the proposed amendments would apply only to affected sources that begin construction, modification, or reconstruction after February 28, 2005. In this action, we are proposing an amended emission limit for PM under 40 CFR part 60, subparts Db and Dc, and no change to the emission limits for SO_2 and NO_X. However, we are requesting public comments on the concept of adopting a single, fuel-neutral emission limit for SO_2 to replace the current 90 percent reduction requirement in the final rule. We are also requesting comment on the possibility of lowering the SO_2 emission limits in 40 CFR part 60, subpart Dc, for units with heat input capacities of 10 MMBtu/hr to 75 MMBtu/hr and developing NO_X emission limits for units subject to 40 CFR part 60, subpart Dc.

1. How Did EPA Select the Proposed PM Limit?

The current PM standards under 40 CFR part 60, subpart Db, for industrial, commercial, and institutional boilers greater than 100 MMBtu/hr heat input range from 0.051 lb/MMBtu heat input to 0.2 lb/MMBtu heat input, depending on the type and amount of fuels burned. The current PM standards under 40 CFR part 60, subpart Dc, for industrial, commercial, and institutional boilers with heat input capacities of 30 MMBtu/hr to 100 MMBtu/hr range from 0.051 lb/MMBtu heat input to 0.3 lb/MMBtu heat input, depending on the type and amount of fuels burned.

We are proposing a PM limit of 0.03 lb/MMBtu heat input for units that burn coal, oil, wood or a mixture of these fuels with other fuels and have a heat input capacity greater than 30 MMBtu/hr. The emission limit is based on the use of fabric filters or high efficiency ESP, which represents BDT. Fabric filters have been shown to achieve greater than 99 percent reduction in PM emissions and may achieve as high as 99.99 percent reduction for some units.

To determine the appropriate limit, we reviewed boiler permit limits and emission information gathered for industrial, commercial, and institutional boilers. Based on this information, we concluded that new boilers can achieve an emission limit of 0.03 lb/MMBtu heat input using a fabric filter or high-efficiency ESP. An emission limit of 0.03 lb/MMBtu heat input is achievable by all industrial, commercial, and institutional boilers considering the wide variety of fuels fired and the range of operating conditions under which those boilers are run.

The proposed NSPS emission limits would not pose significant new costs. New industrial-commercial-institutional steam generating units that are major sources of hazardous air pollutants will be covered also by the National Emission Standards for Hazardous Air Pollutants (NESHAP) for industrial, commercial, institutional boilers and process heaters (40 CFR part 63, subpart DDDDD). The industrial, commercial, institutional boiler and process heater NESHAP require all boilers with a heat input greater than 10 MMBtu/hr and firing solid fuels to meet either a PM limit of 0.025 lb/MMBtu heat input or a total selected metals limit of 0.0003 lb/MMBtu heat input. Liquid-fired units with heat inputs greater than 10 MMBtu/hr must meet a PM limit of 0.03 lb/MMBtu heat input. Accordingly, for most boilers the proposed NSPS would not impose any additional costs because these units are already required to comply with equivalent or more stringent emission limits in the industrial, commercial, institutional boiler and process heater NESHAP.

However, the industrial, commercial, institutional boiler and process heater NESHAP also allow several compliance alternatives that would allow some sources to comply without installing a fabric filter. These alternatives include demonstrating that emissions are below a risk threshold, meeting an alternative metals emission limit, or by demonstrating the metal hazardous air pollutant (HAP) content in the fuel is below the metals emission limit. A review of the data gathered for the industrial, commercial, institutional boiler and process heater NESHAP shows that some wood-fired units are expected to be able to use the alternative compliance options, because wood has a low HAP-to-PM ratio. Therefore, the primary impact of the proposed NSPS would be to require wood-fired boilers to install more efficient controls than would be needed to demonstrate compliance with the industrial, commercial, institutional boiler and process heater NESHAP. For wood-fired boilers, there is a significant flamability risk with fabric filter bags due to particulate loading. Therefore, we analyzed the cost and emissions reductions achieved using a high-efficiency ESP to meet the NSPS limits. Emission test information from industrial, commercial, institutional boilers and utility boilers shows that ESP can achieve the same emissions reductions as fabric filters for these units.

We are projecting that 13 wood-fired units with heat inputs larger than 100 MMBtu/hr will be constructed over the next 5 years. Annual PM emissions would be reduced by 888 tons per year (tpy), from 1,300 tpy, based on the current subpart Db, 40 CFR part 60, emission limits, to 412 tpy with the proposed PM emission limit. The incremental annualized cost of installing and operating an ESP on wood-fired units would be about $2,300 per ton of PM removed.

For the 30 to 100 million Btu/hr size range, we project that four wood-fired units will be constructed over the next 5 years. For these units, annual PM emissions would be reduced by 43 tpy, from about 62 tpy, under the current subpart Dc, 40 CFR part 60, emission limits, to 19 tpy with the proposed PM emission limit. The incremental annualized cost of installing and operating an ESP on a wood-fired unit would be $3,200 per ton of PM removed.

2. How Did EPA Select the Proposed SO_2 Emission Limit?

The existing SO_2 standard for coal- and oil-fired units larger than 75 MMBtu/hr is 90 percent reduction of potential SO_2 emissions and a maximum emission limit of 1.2 lb/MMBtu heat input for coal and 0.8 lb/MMBtu heat input for oil. These limits are based on the use of FGD systems or lime spray dryers. The percent reduction requirement does not apply to units burning fuel oil that have an SO_2 emission potential of 0.5 lb/MMBtu heat input or less. Fluidized bed boilers burning refuse coal are subject to an 80 percent reduction requirement. For small boilers (less than 75 MMBtu/hr) the existing NSPS are based on low sulfur fuels (1.2 lb SO_2/MMBtu heat input).

Based on our review, we are proposing to retain the current SO_2 standard for industrial, commercial, and institutional boilers. In determining BDT, we reviewed the performance of available control technologies and the permits issued for new coal-fired industrial, commercial, and institutional boilers constructed since the publication of 40 CFR part 60, subparts Db and Dc. Based on a review of the information in the Reasonably Available Control Technology/Best Available Control Technology/Lowest Achievable Emission Rate (RACT/BACT/LAER) Clearinghouse, all NSPS units smaller than 75 MMBtu/hr were issued permits to use low sulfur coal. For units greater than 75 MMBtu/hr, the technology used was either lime spray dryers, duct injection, or fluidized-bed boilers with limestone injection. These technologies have been demonstrated to achieve a 90 percent reduction in SO_2. No industrial-commercial-institutional units were found to use wet FGD systems.

To determine BDT, we evaluated two options. Option 1 was to amend subparts Db and Dc, 40 CFR part 60, to adopt a 95 percent reduction requirement for units larger than 75 MMBtu/hr (the size range currently required to meet a 90 percent reduction). Option 2 was to amend subpart Dc, 40 CFR part 60, to require a 90 percent reduction for units smaller than 75 MMBtu/hr.

Option 1 would achieve a 5th year emission reduction of 1,400 tons SO_2 per year (50 percent reduction from the current NSPS) at an incremental cost of about $4,000 per ton removed (table 1 of this preamble). The costs range from $605 per ton removed for some units larger than 250 MMBtu/hr to $12,000 per ton for some units between 100 and 250 MMBtu/hr. The relatively high incremental cost would occur because meeting the 95 percent limit would require a technology switch to more expensive wet FGD systems for many new units. Most new units currently achieve 90 percent reduction using either sorbent injection or spray dryers. Under Option 1, these units would switch to wet FGD systems, because spray dryers and injection technology have not been demonstrated to achieve a 95 percent SO_2 emission reduction. The annualized cost of wet FGD is higher than for these technologies. The cost of wet FGD is about 20 percent higher for large coal-fired units and about 50 percent higher for coal-fired units between 100 and 250 million Btu/hour.

Option 2 would achieve a 5th year emission reduction of 111 tons SO_2 per year (68 percent reduction) for subpart Dc, 40 CFR part 60, units (table 1 of this preamble). The incremental cost-effectiveness would range from about $3,000 to more than $8,000 per ton removed. This cost range represents the cost of applying injection technologies on units of 50 MMBtu/hr and 25 MMBtu/hr, respectively. The relatively high incremental cost would occur because this option would achieve a relatively small additional emissions reductions compared to the current NSPS. Under the current NSPS, units are achieving compliance using low sulfur coals with an emission potential of 1.2 lb SO_2/MMBtu heat input. If the NSPS were changed to require a 90 percent reduction, we project that many new units would select higher sulfur coals because of the reduced fuel cost. For those units that select a higher sulfur coal, a 90 percent reduction in potential SO_2 emission would result in less than a 90 percent reduction in emissions compared to the current NSPS.

Considering these potential impacts, we determined that the current NSPS continues to reflect BDT for 40 CFR part 60, subparts Db and Dc, industrial, commercial, and institutional boilers. The current performance levels can be met by using low sulfur fuels for smaller units and cost-effective control technologies for larger units. Requiring additional control technology would impose unacceptable compliance costs that are not warranted for the emissions reductions that would be achieved.

TABLE 1.—NATIONAL 5TH YEAR IMPACTS OF SO_2 CONTROLS ON INDUSTRIAL BOILERS 2004$

Option	Unit size range (MMBtu/hr)	Emission reduction (tpy)	Annualized cost (million $)	Incremental cost-effectiveness ($/ton)	
				Overall	Range
95 percent [1]	75–250	232	1.68	7,220	6,320–12,060
	>250	1,163	1.56	1,340	610–1,960
90 percent [2 3]	<75	111	0.48	4,280	2,970–8,890

[1] Baseline emissions and emissions reductions used on Option 1 for units greater than 75 MMBtu/hr assume 90 percent SO_2 reduction using a mix of medium sulfur content bituminous coal (2.38 lb SO_2/MMBtu) and subituminous coal (1.41 lb SO_2/MMBtu).
[2] Baseline emissions for units less than 75 MMBtu/hr assume bituminous coal with a 1.2 lb SO_2/MMBtu emission potential.
[3] Emissions reductions were calculated for Option 2 assuming a fuel switch to a 2 to 1 ratio of medium sulfur coal (1.41 lb/MMBtu) to high sulfur coal (6.81 lb/MMBtu).

3. How Did EPA Select the Proposed NO_X Emission Limit?

The current NSPS for NO_X apply to fossil fuel-fired industrial-commercial-institutional steam generating units greater than 100 MMBtu/hr. The NO_X emission limit is 0.2 lb NO_X/MMBtu heat input for units burning coal, oil, or natural gas. Units burning 90 percent or more non-fossil fuel are not required to meet a NO_X emission limit (51 FR 42768). Low heat release rate units that burn more than 30 percent natural gas or distillate oil are required to meet a limit of 0.1 lb NO_X/MMBtu heat input. There are currently no NO_X emission limits for new industrial-commercial-institutional steam generating units less than 100 MMBtu/hr.

The current emission limits for fossil fuel-fired units are based on the application of SCR in combination with combustion controls (*i.e.*, low-NO_X burners). We are not aware of a more effective NO_X control technology for new industrial-commercial-institutional steam generating units. Based on available performance data and cost considerations, the Administrator has concluded that application of SCR with combustion controls represents the BDT (taking into account costs, non-air quality health and environmental impacts, and energy requirements) for coal- and residual oil-fired units.

We, therefore, are proposing to retain the current emission limits for subpart Db, 40 CFR part 60, units. In the 1998 amendments, we presented information that showed that SCR can reduce NO_X emissions from coal-fired utility units to 0.15 lb/MMBtu heat input. However, an emission limit of 0.2 lb/MMBtu heat input was chosen for industrial-commercial-institutional units based on the cost associated with applying flue gas treatment to the wide range of boiler types used in industrial-commercial-institutional applications. Since the 1998 proposal, only eight coal-fired units subject to subpart Db, 40 CFR part 60, have been permitted. Therefore, only limited information is available on the performance of SCR on new coal-fired industrial-commercial-institutional units today. No new performance information or emissions data have been gathered since the 1998 amendments to indicate that lower limits are consistently achievable across the full range of boiler types that may be constructed in the future. In addition, we re-evaluated the costs of SCR. Recent cost information indicates that the cost of operating SCR technology at lower levels than the current standard has not decreased significantly since 1998. We concluded, therefore, that the current emission limits for fossil fuel-fired units constitute BDT (taking into account costs, nonair quality health and environmental impacts, and energy requirements). We are requesting comments and supporting emissions data on the ability of SCR to achieve lower emission limits on fossil fuel-fired industrial-commercial-institutional steam generators and the cost of achieving any lower emission limits.

We are proposing no NO_X emission limits for units with heat input capacities of 100 MMBtu/hr or less (subpart Dc, 40 CFR part 60, units). Information in the RACT/BACT/LAER Clearinghouse shows that in the last 14 years only one coal-fired unit and 16 solid fuel-fired units with heat inputs less than 100 MMBtu/hr have been permitted. Over this same period, 204 units firing natural gas were permitted. This trend is expected to continue. Consequently, new units under 100 MMBtu/hr are expected to be predominantly natural gas-or oil-fired.

One possible control option is to adopt an emission limit based on the performance of low-NO_X burners. This option would have almost no impact on emissions, because most new industrial, commercial, and institutional boilers today are equipped with low-NO_X burners. The primary impact would be to require the installation of a CEMS and impose recordkeeping and reporting requirements to demonstrate that units are continuously meeting the NO_X emission limits. It is unclear that these measures would result in a significant emissions reductions. We, therefore, concluded that the cost of a CEMS to monitor low-NO_X burners is not reasonable for units smaller than 100 MMBtu/hr given that little or no emissions reductions is likely.

We also considered the impact of adopting a 0.2 lb/MMBtu heat input emission limit based on the use of SCR on coal-fired units (table 2 of this preamble). This option would reduce NO_X emissions from subpart Dc of 40 CFR part 60 units by 250 tpy, or about a 10 percent reduction. Given that baseline NO_X emissions from gas-fired units are less than 0.2 lb/million Btu, this limit would have no effect on emissions for the largest projected subset of units operating between 10 and 100 million Btu/hr. Gas-fired units, however, would incur some costs due to monitoring and reporting requirements. Incremental control costs would range from $3,000 to $17,000 per ton removed. Based on these costs, and the factors discussed above, we are proposing not to adopt NO_X emission limits for industrial-commercial-institutional units smaller than 100 MMBtu/hr heat input.

TABLE 2.—NATIONAL 5TH YEAR IMPACTS OF NO_X CONTROL OPTION FOR INDUSTRIAL UNITS SUBJECT TO 40 CFR PART 60, SUBPART DC 2004$

Size range (MMBtu/hr)	Fuel	Number of units	Emission reduction (tpy)	Annual cost (million$)	Incr. cost effect. ($/ton)
30–100	Gas	61	0	2.42	
	Coal	1	34	0.20	5,830
	Liquid	8	126	0.38	3,040
	Wood	4	52	0.90	17,320
10–30	Gas	20	0	0.79	
	Liquid	3	21	.14	6,850
	Wood	2	20	0.18	9,160
Total		99	253	5.02	

* Liquid and gas units can meet the 0.2 lb/MMBtu limit with a Low-NO_X Burner (LNB). Coal and wood units require an SCR to meet the 0.2 limit.

E. What Technical Corrections Is EPA Proposing?

We are proposing several technical corrections to the current subparts Da, Db, and Dc of 40 CFR part 60 requirements in the proposed amendments. The amendments are being proposed to clarify the intent of the current requirements, correct inaccuracies, and correct oversights in previous versions that were promulgated.

Heat Recovery Steam Generators

Heat recovery steam generating units are used to recover energy from the exhaust of combustion turbines.

Some heat recovery steam generators use duct burners or other types of supplemental heat supply to increase the amount of steam production. Depending on the heat input capacity of the supplemental heat in a heat recovery generator, these units may meet the applicability requirements of 40 CFR part 60, subparts Da, Db, and Dc. However, we recognized that these units would be more appropriately regulated as part of the combustion turbine NSPS. In recognition of this, 40 CFR 60.40a(b) and 40 CFR 60.40b(i) provide that when the emission limits for heat recovery steam generators are incorporated into 40 CFR part 60, subpart GG, these units would be subject to 40 CFR part 60, subpart GG, and 40 CFR part 60, subparts Da and Db, would no longer apply. This language was inadvertently left out of 40 CFR part 60, subpart Dc. In a separate action, we are proposing to amend the NSPS for combustion turbines that would be codified as subpart KKKK of 40 CFR part 60 instead of amending subpart GG of 40 CFR part 60. The proposed subpart will include requirements for heat recovery steam generators. Therefore, we are proposing to amend subparts Da, Db, and Dc of 40 CFR part 60 to require heat recovery steam generators to comply with either subpart GG of 40 CFR part 60 or subpart KKKK of 40 CFR part 60 as applicable. The proposed rule language states that ''* * * Heat recovery steam generators that are associated with combustion turbines and meet the applicability requirements of subpart KKKK of 40 CFR part 60 of this part are not subject to this subpart. 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 combustion turbine emissions are subject to 40 CFR part 60, subpart GG, or 40 CFR part 60, subpart KKKK, as applicable, of this part.)''

NO_X Monitoring Requirements for Units Without NO_X Emission Limits

During the 1998 amendments to 40 CFR part 60, subpart Db, we amended the monitoring requirements of 40 CFR 60.48b(b) to allow units that are subject to 40 CFR part 75 (acid rain regulations) to demonstrate compliance with the NSPS by using CEMS that meet the requirements of part 75. In making these amendments, we made a drafting error by inadvertently excluding a phrase from the original NSPS language. The amended 1998 language could be interpreted to require the use of NO_X CEMs for units that are not subject to the NO_X emission limits of 40 CFR part 60, subpart Db. The intended language of 40 CFR 60.48b(b) was, ''* * *, the owner or operator of an affected facility subject to the nitrogen oxides standards of 60.44b shall comply with either * * * *'' (emphasis added to the missing phrase). We did not intend for units without a NO_X emission limit to install CEMS for NO_X. In the proposed amendments, we are adding the inadvertently removed phrase.

Definition of Coal

We are proposing to amend the definition of coal in 40 CFR part 60, subpart Dc, to reflect the most recent testing methods published by the ASTM.

Definitions for 40 CFR Part 60, Subpart Da

We are proposing to add definitions of coal, bitimunous coal, petroleum, and natural gas to 40 CFR part 60, subpart Da, to clarify applicability and make the rules more uniform.

We are also proposing to amend the definition of boiler operating day for new utility units to be consistent with the existing definition for industrial units. The proposed limits reflect the amended procedure utility units would use to calculate 30-day averages. Our preliminary analysis of the hourly CEM data from the Harrison facility indicates that the standards would be approximately 3 percent lower if the existing definition of boiler-operating day is maintained. The amended definition also more accurately reflects environmental performance since less data is excluded from the calculation.

Harmonization of 40 CFR Part 60 and 40 CFR Part 75 Monitoring Requirements

As a continuation and expansion of the ''turbine initiative'' begun by EPA in 2001, we are proposing to harmonize portions of the 40 CFR part 60 continuous emission monitoring regulations with similar provisions in 40 CFR part 75.

Background. In the late 1990's, the electric utility industry began planning and constructing numerous combustion turbine projects, to meet the rising demand for electrical generating capacity in the United States. Essentially all of these new turbines are subject to both 40 CFR part 60, subpart GG, of the NSPS regulations (40 CFR 60.330 through 60.335) and the Acid Rain regulations (40 CFR part 72 through 40 CFR part 78). In an August 24, 2001 **Federal Register** action (66 FR 44622), EPA estimated that as a result of the new turbine projects, the number of combustion turbines in the Acid Rain Program would increase from 400 to more than 1,000 within a few years.

The compliance requirements for combustion turbines under the NSPS and the Acid Rain Program intersect in a number of key places. For instance, under both programs, the owner or operator of an affected combustion turbine is accountable for the SO_2 and NO_X emissions from the unit. In cases such as this, where two Federal regulations affect the same unit for the same pollutant(s), it is always desirable to simplify compliance, to the extent possible. In view of this, in the previously-cited August 24, 2001 **Federal Register** action, EPA requested comments from stakeholders on ways to streamline and harmonize the 40 CFR part 60 and 40 CFR part 75 regulations, in order to facilitate compliance for sources that are subject to both sets of rules. EPA's initiative was directed principally at 40 CFR part 60, subpart GG, combustion turbines that are also in the Acid Rain Program. However, the Agency also asked for comments on ''other needed changes to the regulations,'' at places where the 40 CFR part 60 and 40 CFR part 75 monitoring and reporting requirements overlap.

EPA received several sets of comments in response to the August 24, 2001, **Federal Register** action. After careful consideration of these comments, the Agency proposed substantive amendments to 40 CFR part 60, subpart GG, on April 14, 2003 (68 FR 18003), incorporating many suggestions provided by the commenters. The amendments to 40 CFR part 60, subpart GG, were promulgated on July 8, 2004 (69 FR 41346). The final amendments, which differed little from the proposal, harmonized the 40 CFR part 60, subpart GG, and 40 CFR part 75 regulations in a number of key areas. For example:

(1) Amended 40 CFR part 60, subpart GG, allows the use of a certified 40 CFR part 75 NO_X monitoring system to demonstrate continuous compliance with the NO_X emission limit in 40 CFR 60.332;

(2) If a fuel is documented to be natural gas according to the criteria in appendix D, 40 CFR part 75, then the 40 CFR part 60, subpart GG, requirement to monitor the sulfur content of the fuel is waived; and

(3) A 40 CFR part 60, subpart GG, turbine that combusts fuel oil may use the oil sampling and analytical methods in appendix D, 40 CFR part 75 to demonstrate compliance with the 40 CFR part 60, subpart GG, sulfur-in-fuel limit.

The July 8, 2004 revisions to 40 CFR part 60, subpart GG, significantly simplify compliance with the 40 CFR part 60 and 40 CFR part 75 regulations, where both sets of rules apply to the same combustion turbine. However, the area of overlap between 40 CFR part 60 and 40 CFR part 75 extends beyond combustion turbines. Many electric utility and industrial boilers regulated under 40 CFR part 60, subparts D, Da, Db and Dc, are also subject to 40 CFR part 75. Therefore, a more comprehensive approach to 40 CFR part 60 versus 40 CFR part 75 compliance is needed. A number of stakeholders pointed this out in their comments on the August 24, 2001, **Federal Register** action. In particular, the commenters requested that EPA address the following problematic areas in the 40 CFR part 60 and 40 CFR part 75 continuous emission monitoring provisions:

(1) Inconsistent definitions of operating hours;

(2) Inconsistent CEMS data validation criteria;

(3) Duplicative quality-assurance (QA) test requirements. For instance, many sources with gas monitors are required to perform both 40 CFR part 75 linearity checks and 40 CFR part 60 cylinder gas audits;

(4) Lack of alternative calibration error and relative accuracy specifications in 40 CFR part 60 for low-emitting sources;

(5) Inconsistent span and range requirements for gas analyzers; and

(6) For infrequently-operated units, the difficulty of performing the 40 CFR part 60 calibration drift test over 7 consecutive calendar days.

Today's proposed amendments would address the chief concerns expressed by the stakeholders in their comments on the August 24, 2001, **Federal Register** action, by amending a number of key sections in 40 CFR part 60. The proposed amendments are discussed in detail in the paragraphs below.

Operating Hours and CEMS Data Validation. For all CEMS except opacity monitors, 40 CFR 60.13(h) in the General Provisions of the NSPS requires a minimum of four equally-spaced data points to calculate an hourly emissions average. However, the underlying assumption in the proposed rule text is that the unit operates for the whole hour, and no guidelines are given for validating partial operating hours. Section 60.13(h) also appears to conflict with 40 CFR 60.47a(g), subpart Da, and 40 CFR 60.47b(d) and 40 CFR 60.48b(d), subpart Db, which require only two valid data points to calculate hourly SO_2 and NO_X emission averages. Further, all four of these sections (*i.e.*, 40 CFR 60.13(h), 40 CFR 60.47a(g), 40 CFR 60.47b(d) and 40 CFR 60.48b(d)) are inconsistent with 40 CFR 75.10(d)(1) and with 40 CFR 60.334(b)(2) of the recently-amended 40 CFR part 60, subpart GG, which require you to obtain at least one valid data point in each 15-minute quadrant of the hour in which the unit operates, except for hours in which required QA and maintenance activities are performed for these hours, you may calculate the hourly averages from a minimum of two data points (one in each of two 15-minute quadrants).

Today's proposed amendments would make the CEMS data validation requirements of 40 CFR 60.13(h), 40 CFR 60.47a(g), 40 CFR 60.47b(d) and 40 CFR 60.48b(d) consistent with 40 CFR 75.10(d)(1) and 40 CFR 60.334(b)(2), as follows:

(1) First, a clear distinction would be made in 40 CFR 60.13(h) between full and partial operating hours. A full operating hour would be a clock hour in which the unit operates for 60 minutes, and a partial operating hour would be one with less than 60 minutes of unit operation. To calculate an hourly emissions average for a full operating hour, at least one valid data point would be required in each of the four 15-minute quadrants of the hour. For a partial operating hour, at least one valid data point would be required in each 15-minute quadrant in which the unit operates;

(2) Second, for hours in which required QA or maintenance activities are performed, 40 CFR 60.13(h) would be amended to allow the hourly averages to be calculated from a minimum of two data points (if the unit operates in two or more of the 15-minute quadrants) or one data point (if the unit operates in only one quadrant of the hour);

(3) Third, 40 CFR 60.13(h) would be amended to require all valid data points to be used in the calculation of each hourly average;

(4) Fourth, 40 CFR 60.13(h) would require invalidation of any hour in which a calibration error test is failed, unless in that same hour, a subsequent calibration error test is passed and sufficient data are captured after the passed calibration to validate the hour;

(5) Fifth, 40 CFR 60.13(h) would be amended to make it clear that hourly averages are not to be calculated for certain partial operating hours, where specified in an applicable NSPS subpart (*e.g.*, hours with <30 minutes of unit operation are to be excluded from the calculations under 40 CFR 60.47b(d)); and

(6) Sixth, 40 CFR part 60.47a(g), 40 CFR part 60.47b(d) and 40 CFR part 60.48b(d) would be amended by removing the provisions that allow hourly averages to be calculated from only two data points. Rather, these sections would specify that hourly averages must be calculated according to amended 40 CFR 60.13(h).

These proposed revisions would provide a single, consistent method of calculating hourly emission averages from CEMS data for sources that are subject to both 40 CFR part 60 and 40 CFR part 75. Thus, the same basic set of CEM data could be used for both 40 CFR part 60 and 40 CFR part 75 compliance, although certain differences between the two programs would still remain. For instance, 40 CFR part 75 requires substitute data to be reported for each hour in which sufficient quality-assured data is not obtained to validate the hour, whereas 40 CFR part 60 requires these hours to be reported as monitor down time. Also, 40 CFR part 75 requires a bias adjustment factor (BAF) to be applied to SO_2 and NO_X data when a CEMS fails a bias test, whereas 40 CFR part 60 does not require adjustment of the emissions data for bias. And for certain partial operating hours, data that is reported as quality-assured under 40 CFR part 75 is excluded from the 40 CFR part 60 emission calculations (*e.g.*, see 40 CFR 60.47b(d)). However, these differences between the 40 CFR part 60 and 40 CFR part 75 programs are relatively minor, and in no way detract from the benefits of having a unified approach to reducing the CEMS data to hourly averages.

As noted above, EPA is proposing to remove the provisions in 40 CFR 60.47a(g) of subpart Da and in 40 CFR 60.47b(d) and 40 CFR 60.48b(d) of subpart Db, which require only two valid data points to calculate hourly SO_2 and NO_X emission averages. The reason for this is that these rule texts do not properly communicate the Agency's original intent. The idea of basing an hourly average on two data points was first presented in the preamble for subpart Da, 40 CFR part 60 (44 FR 33581, June 11, 1979). In that preamble, EPA clearly stated that whenever required QA activities such as daily calibration error checks are performed, the Agency would allow the hourly average (assuming it was a full operating hour) to be based on a minimum of two data points instead of the usual four points required by 40 CFR 60.13(h). This relaxation in the data capture requirement for certain operating hours was made with the realization that for many CEMS, calibration checks can take up to 30 minutes, preventing any emissions data from being collected. However, it was never the Agency's intent to replace the four-point data capture requirement of 40 CFR 60.13(h) with a less stringent two-point requirement. The authors of the original 40 CFR part 75 rule understood this, and cited the subpart Da, 40 CFR part 60, preamble as the basis for CFR 75.10(d)(1) (56 FR 63067–68, December 3, 1991). In 40 CFR 75.10(d)(1), at least one valid data point is required to be obtained in each 15-minute quadrant of the hour in which the unit operates, except that two data points, separated by at least 15 minutes may be used to calculate an hourly average if required QA tests or maintenance activities are performed during that hour. More recently, these same minimum data capture requirements have been incorporated into 40 CFR 60.334(b)(2) of subpart GG. In view of these considerations, it is appropriate to remove the two-point minimum data capture provisions from 40 CFR 60.47a(g), 40 CFR 60.47b(d) and 40 CFR 60.48b(d), and simply to require that the

SO_2 and NO_X emission averages be calculated according to amended 40 CFR 60.13(h).

CEMS Certification and Quality-Assurance. Today's proposed amendments would add two sections to appendix F, 40 CFR part 60, pertaining to the on-going quality-assurance requirements for CEMS. These proposed amendments would apply to sources that are subject to the QA requirements of both appendix F, 40 CFR part 60 and appendix B, 40 CFR part 75 and would serve a three-fold purpose: (1) To eliminate duplicative QA test requirements; (2) to allow a single set of data validation criteria to be applied to the CEMS data; and (3) to allow certain alternative 40 CFR part 75 performance specifications for low-emitting sources to be used for 40 CFR part 60 compliance. Today's proposed amendments also would amend section 8.3.1 of performance specification 2 (PS–2) in appendix B, 40 CFR part 60, to allow the 7-day calibration drift test to be performed on 7 consecutive unit operating days, rather than 7 consecutive calendar days.

EPA proposes to add new sections 4.5 and 5.4 to appendix F, 40 CFR part 60. Under proposed section 4.5, sources would be allowed to implement the daily calibration error and calibration adjustment procedures in sections 2.1.1 and 2.1.3 of appendix B, 40 CFR part 75, instead of (rather than in addition to) the calibration drift (CD) assessment procedures in section 4.1 of appendix F, 40 CFR part 60. Sources electing to use this option would be required to follow the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B, 40 CFR part 75 instead of the excessive CD and out-of-control criteria in section 4.3 of appendix F, 40 CFR part 60.

Proposed section 5.4 of appendix F, 40 CFR part 60 would allow sources to perform the quarterly linearity checks described in section 2.2.1 of appendix B, 40 CFR part 75, instead of (rather than in addition to) performing the cylinder gas audits described in section 5.1.2 of appendix F, 40 CFR part 60. If a source elected to use this option, then: (1) The linearity checks would be performed at the frequency prescribed in section 2.2.1 of appendix B, 40 CFR part 75; (2) the linearity error specifications in section 3.2 of appendix A, 40 CFR part 75 would have to be met; (3) the data validation criteria in section 2.2.3 of appendix B, 40 CFR part 75 would be applied in lieu of the excessive audit inaccuracy criteria in section 5.2 of appendix F, 40 CFR part 60; and (4) the grace period provisions in section 2.2.4 of appendix B, 40 CFR part 75 would apply.

Proposed section 5.4 of appendix F, 40 CFR part 60 also would allow sources to perform the on-going quality-assurance relative accuracy test audit (RATA) of their NO_X-diluent and SO_2-diluent monitoring systems according to section 2.3 of appendix B, 40 CFR part 75. If a source elected to use this option, then: (1) The RATA frequency would be as specified in section 2.3.1 of appendix B, 40 CFR part 75; (2) the applicable relative accuracy specification in Figure 2 of appendix B, 40 CFR part 75 would have to be met; (3) the data validation criteria in section 2.3.2 of appendix B, 40 CFR part 75 would be applied in lieu of the excessive audit inaccuracy criteria in section 5.2 of appendix F, 40 CFR part 60; and (4) the grace period provisions in section 2.3.3 of appendix B, 40 CFR part 75 would apply.

These proposed amendments to appendix F, 40 CFR part 60 would greatly simplify compliance without sacrificing data quality. Currently, sources that are required to perform periodic QA testing under both appendix F, 40 CFR part 60, and appendix B, 40 CFR part 75, have two reference frames for CEMS data validation. Neither the CEMS performance specifications nor the out-of-control criteria are the same in the two appendices. Generally speaking, the 40 CFR part 75 specifications and data validation criteria are more stringent than those of 40 CFR part 60. For example, when daily calibrations are performed, appendix F, 40 CFR part 60, allows the calibration drift of an SO_2 or NO_X monitor to exceed 5 percent of span for 5 consecutive days before the monitor is declared out-of-control. Under appendix B, 40 CFR part 75, however, a monitor is considered out-of-control whenever the results of a daily calibration check exceed 5 percent of span. For a 40 CFR part 75 linearity check, three calibration gases are used (as opposed to two gases for a part 60 cylinder gas audit (CGA)), and the linearity error (LE) specification (*i.e.*, LE ≤5 percent of the reference gas concentration) is much more stringent than the CGA acceptance criterion of 15 percent. For RATA, the principal 40 CFR part 75 relative accuracy specification is 10 percent, whereas the appendix F, 40 CFR part 60, specification is 20 percent. Thus, it is safe to say that the data from a CEMS that meets the quality-assurance requirements of appendix B, 40 CFR part 75 may be used with confidence for the purposes of 40 CFR part 60 compliance.

Allowing sources to perform the 40 CFR part 75 QA in lieu of (rather than in addition to) appendix F, 40 CFR part 60, is actually consistent with section 1.1 of appendix F, 40 CFR part 60, which encourages sources to ''develop and implement a more extensive QA program or continue such programs where they already exist.'' It also harmonizes with 40 CFR 60.47a(c)(2) of subpart Da, 40 CFR 60.48b(b)(2) of subpart Db, and 40 CFR 60.334(b)(3)(iii) of subpart GG, which allows certified 40 CFR part 75 NO_X monitoring systems to be used to demonstrate compliance with the applicable NO_X emission limits. However, despite these clear statements in the amendments, today's proposed amendments to appendix F, 40 CFR part 60 are needed to eliminate any doubt that meeting the quality-assurance testing requirements of appendix B, 40 CFR part 75, fully satisfies the requirements of appendix F, 40 CFR part 60. Many operating permits have required sources to implement both appendix B, 40 CFR part 75, and appendix F, 40 CFR part 60, QA procedures for their CEMS. This has proved to be burdensome, not only because of the previously-mentioned differences in the specifications and data validation criteria between the two appendices, but also because 40 CFR part 60 cylinder gas audits and 40 CFR part 75 linearity checks are so similar in nature (*i.e.*, they are essentially two tests of the same type). Since the linearity check is far more stringent than the CGA, many sources have questioned why CGA are necessary if quarterly linearity checks are being performed. Today's proposed amendments would effectively eliminate this duplicative QA test requirement.

EPA is also proposing to amend section 8.3.1 of PS–2 in appendix B, 40 CFR part 60, to allow the 7-day calibration drift test, which is performed for the initial certification of a CEMS, to be performed on 7 consecutive unit operating days, rather than 7 consecutive calendar days. The intent of the proposed amendment is to provide regulatory relief to infrequently-operated units. Many new sources (particularly gas turbines) seldom, if ever, operate for 7 consecutive days, making the 7-day drift test difficult to perform. Allowing the test to be performed on 7 consecutive operating days should make the test much easier to complete within the time allotted for initial certification. The proposed amendment is consistent with section 6.3.1 in appendix A, 40 CFR part 75, and with 40 CFR 60.334(b)(1) of subpart GG.

CEM Span Values. Today's proposed amendments would amend several sections of subparts D, Da, Db, and Dc, 40 CFR part 60, pertaining to CEM span values. The span values for SO_2 and NO_X monitors under subparts D, Da, Db and Dc, 40 CFR part 60, are fuel-specific and are rather prescriptive. For example, subparts D, Da and Db, 40 CFR part 60, all require a NO_X span value of 1000 part per million (ppm) for coal combustion and 500 ppm for oil and gas combustion. Subpart D, 40 CFR part 60 requires a 1500 ppm SO_2 span value for coal combustion, and subparts Da, Db and Dc, 40 CFR part 60, all require the span value of the SO_2 monitor installed on the control device outlet to be 50 percent of the maximum estimated hourly potential SO_2 emissions for the type of fuel combusted.

Under 40 CFR part 75, SO_2 and NO_X span values are determined in quite a different manner. Sources are required to determine the maximum potential concentration (MPC) of SO_2 or NO_X and then to set the span value between 1.00 and 1.25 times the MPC, and select a full-scale measurement range so that the majority of the data recorded by the monitor will be between 20 and 80 percent of full-scale. The full-scale range must be greater than or equal to the span value.

Under 40 CFR part 75, units are allowed to determine the MPC values in a number of different ways, *e.g.*, using a fuel-specific default value, emission test data, historical CEM data, etc. Units with add-on SO_2 or NO_X emission controls are further required to determine the maximum expected concentration (MEC), which is the highest concentration expected with the emission controls operating normally. If the MEC is less than 20 percent of the high scale range, then a second (low-scale) measurement range is required.

The span value is an important concept in 40 CFR part 60 and 40 CFR part 75, for two reasons. First, the concentrations of the calibration gases used for daily calibrations, cylinder gas audits, and linearity checks are expressed as percentages of the span value (*e.g.*, under 40 CFR part 75, a ''mid'' level gas is 50 to 60 percent of span). Second, the maximum allowable calibration error (CE) for daily calibration checks of SO_2 and NO_X monitors is expressed as a percentage of the span value (*i.e.*, CE ≤5 percent of span). In view of this, it is essential that the span values be properly-sized, in order to ensure the accuracy of the CEM measurements. For example, suppose that a coal-fired unit is subject to both subpart Da, 40 CFR part 60, and the Acid Rain Program. The owner or operator installs low-NO_X burners to meet the NO_X emission limit under 40 CFR part 76, and the actual NO_X readings are consistently between 150 and 200 ppm. Subpart Da, 40 CFR part 60, would require a span value of 1000 ppm for this unit, but this span would be too high for 40 CFR part 75, since the NO_X data would be consistently on the lower 20 percent of the measurement scale. Also, by using a span value of 1000 ppm, the ''control limits'' on daily calibration error tests would be ±5 percent of span, or ±50 ppm. Thus, when measuring a true NO_X concentration of 150 ppm, the NO_X monitor could be off by as much as 50 ppm (*i.e.*, by 33 percent) and the monitor would still be considered to be ''in-control.''

In view of this, it is evident that some of the differences between the 40 CFR part 60 and 40 CFR part 75 span provisions are not easily reconcilable, and this raises certain legal and compliance issues. For instance, in the example cited above, if the owner or operator elects to use a 500 ppm NO_X span value to meet the requirements of part 75, it is not clear whether he would still be required to maintain a 1,000 ppm span value to satisfy subpart Da, 40 CFR part 60. To address these issues, EPA is proposing to amend several sections of subparts D, Da, Db and Dc, 40 CFR part 60, pertaining to the determination of SO_2 and NO_X span values. The affected sections are 40 CFR 60.45(c)(3) and (4) of subpart D, 40 CFR 60.47a(i)(3), (4), and (5) of subpart Da, 40 CFR 60.47b(e)(3), 40 CFR 60.48b(e)(2) and (3) of subpart Db, and 40 CFR 60.46c(c)(3) and (c)(4) of subpart Dc. The proposed amendments would allow SO_2 and NO_X span values determined in accordance with section 2 of appendix A, 40 CFR part 75, to be used in lieu of the span values prescribed by 40 CFR part 60.

Electric Utility Steam Generating Unit

A CHP unit that meets the definition of an electric utility steam generating unit is subject to 40 CFR part 60, subpart Da. Under 40 CFR part 60, subpart Da, an electric utility steam generating unit means ''* * * any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electric output to any utility power distribution system for sale.'' We recognize that under certain utility rate structures, it is more economical for CHP facilities to sell all electric output to the grid and then meter back electric power for non-utility plant use. The intent of the definition of an electric utility steam generating unit under subpart Da, 40 CFR part 60, is to consider net sales and not gross sales to the grid. Therefore, we are proposing to amend the definition to change ''electric output'' to ''net electric output'' and to define net electric output as ''gross electric sales to the electric distribution system minus purchased power on a 30-day rolling average.''

V. Modification and Reconstruction Provisions

Existing steam generating units that are modified or reconstructed would be subject to today's proposed amendments. Analysis of acid rain and ozone season data for existing sources indicates that reconstructed and modified units should be able to achieve the proposed standards.

A modification is any physical or operational change to an existing facility which results in an increase in the facility's emission rate (40 CFR 60.14). Changes to an existing facility that do not result in an increase in the emission rate, either because the nature of the change has no effect on emission or because additional control technology is employed to offset an increase in the emission rate, are not considered modifications. In addition, certain changes have been exempted under the General Provisions (40 CFR 60.14). These exemptions include an increase in the hours of operation, addition or replacement of equipment for emission control (as long as the replacement does not increase the emission rate), and use of an alternative fuel if the existing facility was designed to accommodate it.

Rebuilt steam generating units, as defined in section 63.2, would become subject to the proposed amendments under the reconstruction provisions, regardless of changes in emission rate. Reconstruction means the replacement of components of an affected facility such that; (1) the fixed capital cost of the new components exceeds 50 percent of the cost of an entirely new steam generating unit of comparable design, and (2) it is technologically and economically feasible to meet the applicable standard (40 CFR 60.15).

VI. Summary of Cost, Environmental, Energy, and Economic Impacts

In setting the standards, the CAA requires us to consider alternative emission control approaches, taking into account the estimated costs and benefits, as well as the energy, solid waste and other effects. The EPA requests comment on whether it has identified the appropriate alternatives and whether the proposed standards adequately take into consideration the incremental effects in terms of emission reductions, energy and other effects of these alternatives. The EPA will consider the available information in developing the final rule.

The costs, environmental, energy, and economic impacts are expressed as incremental differences between the impacts of utility and industrial-commercial-institutional steam generating units complying with the proposed amendments and the current NSPS emission limits (*i.e.*, baseline). The impacts are presented for new steam generating units constructed over the next 5 years.

For the electric utility sector, The Energy Information Administration forecasts 1,300 MW of new coal-fired electric utility steam generating units will be built during the next 5 years. We used permit data and engineering judgement to determine that the distribution of these new units by type of coal burned would be as follows: two bituminous coal-fired units, two subbituminous coal-fired units, and one coal refuse-fired unit. All new natural gas-fired electric utility generating units built in the foreseeable future will most likely be combined cycle units or combustion turbine peaking units and, thus not subject to subpart Da, 40 CFR part 60, but instead subject to the NSPS for combustion turbines under 40 CFR part 60, subpart GG, or subpart KKKK of 40 CFR part 60. Furthermore, because of fuel supply availability and cost considerations, we assumed that no new oil-fired electric utility steam generating units will be built during the next 5 years.

For the industrial-commercial-institutional sector, we project that 87 new steam generating units larger than 100 million Btu per hour will be built and 99 new steam generating units between 10 and 100 million Btu per hour will built over the next 5 years. Of these 186 projected new units, we estimate 8 new coal units, 133 natural gas units, 21 biomass units, 22 liquid fuel units, and 2 non-fossil solid fuel units. Of the biomass units, only 17 are wood-fired and would be impacted by the proposed amendments.

The combined impact of the proposed amendments (compared to the existing NSPS) is to reduce SO_2 emissions by about 8,400 tpy, NO_X emissions by about 1,400 tpy, and PM emissions by about 1,500 tpy. The annualized cost of achieving these reductions in new source emissions is about $6.5 million. The cost and environmental impacts for each proposed amendment are summarized below.

A. What Are the Impacts for Electric Utility Steam Generating Units?

As discussed earlier, cap and trade programs and new source review often result in new utility units installing controls beyond what is required by the existing NSPS. Since only the existing NSPS set specific limits, we are using those standards as the baseline to be conservative in our estimating of costs. Actual costs (and benefits) of the proposed amendments could be less than stated in our analysis. Also, for pollutants and geographic regions regulated by cap and trade programs, most new units would install controls as tight or tighter than the proposed amendments. Therefore, the proposed amendments would not significantly impact allowance prices or costs for existing utility sources.

The primary environmental impacts resulting from the proposed amendments to subpart Da of 40 CFR part 60 for electric utility steam generating units are further reductions in the amounts of PM, SO_2, and NO_X that would be emitted from new units subject to subpart Da of 40 CFR part 60. Achieving these additional emissions reductions would increase the costs of installing and operating controls by approximately 4 percent on a steam generating unit subject to the proposed standards above those costs for the unit to comply with the applicable existing standards under subpart Da of 40 CFR part 60. In general, the same types of the PM, SO_2, and NO_X controls would be installed on a given unit to comply with either of the applicable existing or proposed standards. However, there would be an increase in the capital and annual costs for these controls to achieve the higher performance levels needed for the proposed standards due to design modifications and operating changes to the controls. The estimated nationwide 5-year incremental emissions reductions and cost impacts for the proposed standards beyond those estimated for the regulatory baseline are summarized in Table 3 of this preamble.

TABLE 3.—NATIONAL EMISSIONS REDUCTIONS AND COST IMPACTS FOR ELECTRIC UTILITY STEAM GENERATING UNITS SUBJECT TO AMENDED STANDARDS UNDER SUBPART DA OF 40 CFR PART 60

[5th Year after proposal]

Pollutant	Annual emissions reductions (tpy)	Total capital investment cost ($ million/yr)	Annualized cost ($ million/yr)
PM	530	$10.4	$2.2
SO_2	8,400	$0.9	$0.7
NO_X	1,400	$4.9	$1.5

1. PM Impacts

The impact of new source review is not included in our baseline so actual costs (and benefits) of the proposed amendments could be less than stated in our analysis. The regulatory baseline for PM emissions is defined to be installation of fabric filters on all new units (*i.e.*, electric utility companies would install fabric filters to comply with the PM standard under the existing NSPS). Design modifications and operating changes to the fabric filters would be required to achieve the higher performance level needed to comply with the proposed PM standard.

Estimated baseline PM emissions from the projected new electric utility steam generating units are approximately 960 megagrams per year (Mg/yr) (1,100 tpy). The proposed standards are projected to reduce PM emissions by 480 Mg/yr (530 tpy). This represents an approximate 50 percent reduction in the growth of PM emissions from new units that would be subject to the proposed standards.

The nationwide increases in total capital investment costs and the annual operating costs of the control equipment required to meet the proposed PM standards over the baseline costs are estimated to be $10.4 million and $2.2 million per year, respectively.

Compliance with the proposed PM standard would increase the quantity of fly ash collected by the fabric filters over the baseline levels. Depending on the practices used at a given power plant site, this would increase the amount of fly ash the utility company can recycle as a by-product (*e.g.*, sell as raw material for concrete or roadway fill material) or increase the amount of fly ash the company must dispose of as a solid waste either on-site or off-site. No significant energy impacts, as measured relative to the regulatory baseline, are expected as a result of the proposed PM standard.

2. SO_2 Impacts

The impacts of new source review and the acid rain trading program are not included in our baseline so actual costs (and benefits) of the proposed amendments could be less than stated in our analysis. The regulatory baseline for SO_2 emissions is defined to be the installation of one of three SO_2 control configurations, depending on the type of coal burned. New units burning bituminous coal were assumed to use pulverized coal-fired boilers equipped with limestone wet scrubbers with forced oxidation. New units burning low sulfur, subbituminous coal were assumed to use either spray dryers or LSFO depending on the boiler size. New units burning lignite or coal refuse were assumed to use circulating fluidized-bed (CFB) boilers with limestone addition. Design modifications and operating changes to these baseline controls would be required to achieve the higher performance level needed to comply with the proposed SO_2 standards.

Estimated baseline SO_2 emissions from the projected new electric utility steam generating units are approximately 14,000 Mg/yr (16,000 tpy). The proposed standards are projected to reduce SO_2 emissions by 7,600 Mg/yr (8,400 tpy). This represents an approximate 48 percent reduction in the growth of SO_2 emissions from new units that would be subject to the proposed standards. The proposed limit is approximately 65 percent lower than the existing limit, but many of the baseline units are over complying by using low sulfur coals.

The nationwide increases in total capital investment cost and the annual operating cost of the control equipment required to meet the proposed standards over the baseline costs are estimated to be $0.9 million and $0.7 million per year, respectively.

For steam generating units using LSFO, compliance with the proposed SO_2 standard would increase the quantity of scrubber sludge over the baseline levels. Depending on the practices used at a given power plant site, the resulting scrubber sludge (mostly calcium sulfite hemihydrate and gypsum) is disposed of in a landfill or is recovered as a salable by-product (*e.g.*, sold to a wallboard manufacturer). For those units using a dry scrubber or a CFB with limestone addition, the dry reaction solids are entrained in the flue gases, along with fly ash, and then collected by the downstream particulate control device. Compliance with the applicable proposed SO_2 standard would increase the quantity of solid materials collected by the particulate control devices over the baseline levels. No significant energy impacts, as measured relative to the regulatory baseline, are expected as a result of the proposed SO_2 standard.

3. NO_X Impacts

The impact of new source review is not included in our baseline so actual costs (and benefits) of the proposed amendments could be less than stated in our analysis. The regulatory baseline for NO_X emissions is defined to be installation of SCR controls on all new pulverized coal-fired units burning bituminous or subbituminous coal, and no additional NO_X controls on the CFB units burning lignite or coal refuse. Design modifications and operating changes to the SCR systems would be required to achieve the higher performance level needed to comply with the proposed NO_X standard. Installation and use of SNCR systems on the CFB units burning lignite or coal refuse is assumed to be needed to comply with the proposed NO_X standard.

Estimated baseline NO_X emissions from the projected new electric utility steam generating units are approximately 4,700 Mg/yr (5,200 tpy). The proposed standards are projected to reduce NO_X emissions by 1,200 Mg/yr (1,400 tpy). This represents an approximate 26 percent reduction in the growth of NO_X emissions from new units that would be subject to the proposed standards. The proposed limit is approximately 38 percent lower than the existing limit, but CFB baseline units are over complying with the existing limit.

The nationwide increases in total capital investment costs and the annual operating costs of the control equipment required to meet the proposed standards over the baseline costs are estimated to be $4.9 million and $1.5 million per year, respectively. These cost estimates may overstate the actual costs to meet the proposed NO_X standard because of the assumption used for the analysis that the CFB units burning lignite or coal refuse can meet the existing NO_X standard in subpart Da of 40 CFR part 60 without the need to install flue gas controls for NO_X emissions. Thus, the estimated costs include the full costs of installing SNCR systems on the CFB units to meet the proposed NO_X standard. Also, data for some western subbituminous coals suggests that the NO_X emission levels from burning these coals will be lower than the baseline NO_X emission levels used for the cost analysis.

Using nitrogen-based reagents requires operators of SCR and SNCR systems to closely monitor and control the rate of reagent injection regardless of the level of an applicable emission standard. If injection rates are too high, emissions of ammonia from a steam generating unit using SCR or SNCR may be in the range of 10 to 50 ppm. No significant energy impacts, as measured relative to the regulatory baseline, are expected as a result of the proposed NO_X standard.

B. What Are the Impacts for Industrial, Commercial, Institutional Boilers?

The nationwide increase in annualized costs for new industrial-commercial-institutional steam generating units greater than 100 MMBtu/hr heat input is about $2.1 million in the 5th year following proposal (table 4 of this preamble). This cost reflects the cost for wood-fired and wood and other fuel co-fired units to comply with the proposed PM limit. The cost-effectiveness for affected boilers under the proposed PM standard was $2,400 per ton removed. The proposed standard would impose no additional costs on fossil fuel-fired boilers.

The nationwide increase in annualized costs for new industrial-commercial-institutional units operating between 30 and 100 MMBtu/hr is about $140,000 in the 5th year following proposal. This cost reflects the control and monitoring cost for wood units to comply with the proposed PM limit. The range in cost-effectiveness for affected boilers under the proposed PM standard for subpart Dc of 40 CFR part 60 was about $3,200 per ton for high moisture wood units to about $3,500 per ton for dry wood-fired units.

TABLE 4.—NATIONAL COST AND EMISSION IMPACTS FOR INDUSTRIAL STEAM GENERATING UNITS

[5-Year impacts]

Subpart	Number of units	Emission reduction (tpy)	Annualized cost (million $)	Incremental cost-effectiveness ($/ton)	
				Overall	Range
Db	13	888	2.11	2,372	2,352–2,577
Dc	4	43	0.14	3,227	3,142–3,479

The range represents the difference in cost-effectiveness between wet and dry wood fuels.

The primary environmental impact resulting from the proposed PM standards is a reduction in the amount of PM emitted from new steam generating units. The estimated emissions reductions in the 5th year following proposal is about 840 Mg/yr (930 tpy) for subparts Db and Dc of 40 CFR part 60 units combined (about a 70 percent reduction for wood-fired units).

Secondary emission impacts would occur as a result of the additional electricity required to operate PM controls. A range of secondary air impacts for five criteria pollutants is shown in table 5 of this preamble. The range of impacts represents the instances where all electricity is generated off-site versus on-site.

There would be no significant impacts on the discharges to surface waters as a result of the proposed amendments to the PM standard. Fabric filter and ESP technologies do not demand water resources to control PM.

Solid waste impacts result from disposal of the PM collected in the fabric filter or ESP control device. The estimated solid waste impacts are 1,400 Mg/yr (1,500 tpy) for new industrial-commercial-institutional units at the end of the 5th year following proposal. The estimated costs of handling the additional solid waste generated are $33,000 for new industrial-commercial-institutional units greater than 100 MMBtu/hr and $1,600 for new industrial-commercial-institutional sources operating between 30 and 100 MMBtu/hr.

The proposed amendments require additional energy to operate fans on ESP controls. The estimated additional energy requirements are 4.1 million kilowatt hours (kWh) for new industrial-commercial-institutional units greater than 100 MMBtu/hr and 0.2 million kWh for new units between 30 and 100 MMBtu/hr. This additional energy requirement is estimated at about 0.1 percent of the boiler output.

TABLE 5.—ENVIRONMENTAL IMPACTS OF INDUSTRIAL UNITS

[5-Year impacts]

Subpart	Secondary air impacts (tpy)					Solid waste (tpy)	Energy (kWh/yr)
	SO_2	NO_X	CO	PM	VOC		
Db	0–83	12–50	0–34	1–33	0–2	1,482	4,063,397
Dc	0–3	0–2	0–1	0–1	0	69	167,860

A range of secondary air impacts represent emissions from electricity generated on-site vs. off-site. On-site generation assumed the use of wood fuel, and off-site generation assumed the use of coal for electricity generation.

C. Economic Impacts

Utilities. The analysis shows minimal changes in prices and output for the industries affected by the final rule. The price increase for baseload electricity is 0.23 percent and the reduction in domestic production is 0.05 percent. The analysis also shows the impact on the distribution of electricity supply. First, the construction of the five units with add-on controls may be delayed; hence the engineering cost analysis of controls are not incurred by society. Therefore the social costs of the proposed standard are approximately $0.7 million and reflect costs associated with existing units bringing higher-cost capacity online and consumers' welfare losses associated with the price increases and quantity decreases in the electricity market. However, this estimate of social costs does not account for the benefits of emissions reductions associated with this proposed New Source Performance Standard (NSPS). For more information on these impacts, please refer to the economic impact analysis in the public docket.

Industrial, Institutional, and Commercial Boilers. Based on economic impact analysis, the amendments are expected to have a negligible impact on the prices and production quantities for both the industry as a whole and the 17 affected entities. The economic impact analysis shows that there would be less than 0.01 percent expected price increase for output in the 17 affected entities as a result of the amendments for wood-fueled industrial boilers, subparts Db and Dc of 40 CFR part 60. The estimated change in production of affected output is also negligible with less than a 0.01 percent change expected. In addition, impacts to affected industries show that prices of lumber and wood products, as well as paper and allied products, would not change as a result of implementation of the amendments as proposed, and output of these types of manufacturing industries would remain the same. Therefore, it is likely that there is no adverse impact expected to occur for those industries that produce output affected by the proposed amendments, such as lumber and wood products and paper and allied products manufacturing. For further information, please refer to the economic impact analysis in the public docket.

VII. Request for Comments

We request comments on all aspects of the proposed amendments. All significant comments received will be considered in the development and selection of the final amendments. We specifically solicit comments on additional amendments that are under consideration. These potential amendments are described below.

Industrial Boiler SO_2 Standard. We are requesting additional information on the ability of industrial boilers fueled by inherently low sulfur fuels to achieve a 90 percent reduction. Preliminary information indicates that industrial boilers using fuels with inherently low SO_2 emissions encounter technical difficulties achieving 90 percent sulfur removal. With this issue in mind, we are considering replacing the SO_2 percent reduction requirement in subparts Db and Dc of 40 CFR part 60 with a single, fuel-neutral emission limit in the final rule. Also, we would like comments on whether this change, if it is made, should be available for existing units or only apply to new units.

The emission limit could be expressed in either an output-based or input-based format. Either format would not create disincentives for the use of inherently low sulfur fuels. In addition, using an emission limit format exclusively may have benefits for industrial boilers in terms of compliance flexibility. Our initial analysis indicates that FGD systems can economically reduce SO_2 emissions from industrial, commercial, and institutional coal-fired boilers to 100 ng/J (0.24 lb/MMBtu heat input) heat input or less. The corresponding optional output-based emission limit would be 320 ng/J (2.6 lb SO_2 per MWh) of gross electrical output.

If we adopt a 0.24 lb SO_2/MMBtu heat input emission limit, as we are considering doing, the impacts depend on the mix of coals that are burned in new industrial boilers. For units burning coal with an emission potential greater than 2.4 lb SO_2/MMBtu heat input, control costs would be higher and emissions lower than under the current NSPS because more than a 90 percent reduction in emissions would be required. For units burning coal with an emission potential less than 2.4 lb SO_2/MMBtu heat input, control costs would be reduced and allowable emissions would be somewhat higher than the current NSPS. Industrial boilers using coal with an emission potential of 2.4 lb SO_2/MMBtu heat input would experience no difference in required control, but compliance costs would be lower because the testing and monitoring costs of complying with an emission limitation would be less than for a percent reduction standard, which requires testing at the inlet and outlet of the control device.

Preliminary analysis shows that a 0.24 lb/MMBtu standard would reduce emissions by 40 tpy with a small net cost savings. This analysis is based on the projection of six new coal-fired units with an SO_2 emission potential of 2.4 lb SO_2/MMBtu heat input or less, and one new boiler co-firing coal and wood with an emission potential of 3.0 lb SO_2/MMBtu heat input.

We request comments on the advantages and disadvantages of amending the current 40 CFR part 60, subpart Db and Dc, standards to an SO_2 emission limitation only and the likely cost and emissions reductions impacts. We also solicit data on the sulfur content of coals used by industrial boilers and future market projections.

If we adopt an emission limit format, we solicit comments on whether the emission limit should be expressed in an input-based or output-based format. In the 1998 NSPS amendments, we concluded that an output-based format provided only limited opportunity for promoting energy efficiency at subpart Db, 40 CFR part 60, units. In addition, we concluded that an output-based format could impose additional hardware and software costs because instrumentation to measure energy output generally did not exist at industrial-commercial-institutional facilities. In the case that we decide to replace the percent reduction requirement for 40 CFR part 60, subpart Db, and 40 CFR part 60, subpart Dc, units, we solicit comments on the benefits and costs of adopting an output-based emission limit either as the sole emission limit or as an optional emission limit.

An alternate approach we are considering and would like comment on is maintaining the percent reduction requirement and establishing an alternate emission limit. Under this approach, all units would comply with either an emissions limit of 0.2 lb SO_2/MMBtu or a 95 percent reduction. We would like comments both on this approach and appropriate limits.

Selection of Optional Output-Based NO_X Emission Limit for 40 CFR Part 60, Subpart Db, Units That Generate Electricity

For industrial-commercial-institutional units that generate electricity, we are considering an optional output-based emission limit in units of pounds of pollutant per MWh of gross energy output. Ideally, the output-based emission limit would be based on emissions data and energy output data that were measured simultaneously. However, output-based emission data are not readily available for industrial steam generating units. Most emission test data today are reported based on energy input, consistent with current State and Federal compliance reporting requirements. In the absence of measured output-based data, we would develop the emission limit using input-based emissions data and a baseline energy generating efficiency.

To develop the emission limit, we would use a baseline gross electrical generating efficiency of 32 percent, or a corresponding heat rate of 10.667 MMBtu/MWh. Most existing electric utility steam generating units achieve an overall efficiency of 29 to 38 percent, with newer units trending to the upper end of that range. However, given the diverse use of industrial-commercial-institutional steam generating unit applications, and since these units are primarily designed for providing process steam and not optimized for electrical production, we decided that applying an efficiency of 38 percent (*i.e.*, at the high end of the efficiency range) would be unreasonable. The output-based emission limit was, therefore, calculated by multiplying the input-based emission limit by the heat rate corresponding to a 32 percent gross electrical generating efficiency. Given a NO_X emission limit of 86 ng/J (0.2 lb/MMBtu heat input) for fossil fuel-fired units, we are proposing a corresponding output-based emission limit of 270 ng/J (2.1 lb/MWh). If you choose to comply with the optional output-based emission limit for your unit, then you must demonstrate compliance based on a 30-day rolling average. This averaging period is consistent with the input-based emission limit requirements, and it provides a sufficient averaging period to account for any variability in unit operating efficiency.

Applicability of the Industrial-Commercial-Institutional Boiler PM standard. The existing emission limits for PM in 40 CFR part 60, subpart Db, and 40 CFR part 60, subpart Dc, apply only to coal, oil, and wood-fired units. We are considering and requesting comment on extending the applicability of the proposed NSPS to cover all solid fuel-fired fuels in the final rule. A review of the BACT/LAER database revealed that since 1991, construction permits have been issued for seven units burning bagasse, two units burning hull fuel, and nine units burning non-fossil fuel (*e.g.*, wastewater sludge and tire-derived fuel). Emissions data indicate that these fuels are capable of meeting the same emission limits as coal-fired units. We solicit comment on the cost, environmental, and economic implications of extending the applicability of the proposed PM emission limits for 40 CFR part 60, subpart Db, and 40 CFR part 60, subpart Dc, to all solid fuels. Assuming use of a mechanical collector as the basis for baseline controls, preliminary analysis indicates that PM emissions could be reduced by 134 tpy at an incremental cost of about $1,700 per ton removed.

Reporting Requirements for 40 CFR Part 60, Subpart Dc. Natural gas-fired units and low sulfur oil-fired units fall under the applicability of 40 CFR part 60, subpart Dc, due to the heat input capacity of the unit, but have no applicable emission limits. However, subpart Dc of 40 CFR part 60 requires daily fuel usage recordkeeping for natural gas and low sulfur oil under section 60.48c(g) to ensure that no other fuels are being burned in combination with them. Since no emission limits apply to these units, we are considering amending the reporting requirements in 40 CFR 60.48c(g) of subpart Dc for units permitted to fire only natural gas or low sulfur oil from daily to monthly. This reduction in burden is consistent with recordkeeping alternatives approved by EPA and will reduce the reporting burden for those facilities that currently report fuel usage on a daily basis.

Output-based PM Emission Limit for 40 CFR Part 60, Subpart Da. The proposed amendments to 40 CFR part 60, subpart Da, for electric utility steam generating units would establish output-based emission limits for SO_2 and NO_X. Although we prefer to use output-based formats for all of the emission limits applicable to an electric utility steam generating unit subject to the proposed standards, the proposed emission limit for PM retains the heat input format while we continue to evaluate PM CEMS. We are considering converting the proposed PM emission limit to an output-based format and requiring PM CEMS for the final rule.

For more than two decades, CEMS have been used in Europe to monitor PM emissions from a variety of industrial sources, including electric utility steam generating units. In the United States, however, PM CEMS presently are not routinely used to monitor emissions from coal-fired electric utility steam generating units. However, several electric utility companies in the United States have now installed or are planning to install PM CEMS on electric utility steam generating units.

In recognition of the fact that PM CEMS are commercially available, we have developed and promulgated PS and QA procedures for PM CEMS (69 FR 1786, January 12, 2004). Performance specifications for PM CEMS are established under PS–11 in appendix B to 40 CFR part 60 for evaluating the acceptability of a PM CEMS used for determining compliance with the emission standards on a continuous basis. Additional quality assurance procedures are established under procedure 2 in appendix F to 40 CFR part 60 for evaluating the effectiveness of quality control and quality assurance procedures and the quality of data produced by the PM CEMS.

Based on our analysis of available data, there is no technical reason that PM CEMS cannot be installed and operate reliably on electric utility steam generating units. Thus, the availability of PM CEMS makes establishing an output-based PM emission limit under 40 CFR part 60, subpart Da, a realistic option. We are requesting comment on the application of PM CEMS to electric utility steam generating units, and the use of data from such systems for compliance determinations under 40 CFR part 60, subpart Da.

For an output-based PM standard, we would convert the proposed PM emission limit of 0.015 lb/MMBtu heat input to the corresponding value in units of lb/MWh using an overall electrical generating efficiency of 36 percent. The resulting PM emission limit would be 18 ng/J (0.14 lb/MWh) gross electricity output as determined on a 30-day rolling average basis. The unit owner or operator would not be required to conduct the periodic performance tests required for demonstrating compliance with the input-based emission limit. In lieu of these performance testing requirements, under the proposed amendments the owner or operator would be required to install and operate a PM CEMS and demonstrate compliance with the alternative PM standard following the same procedures used to demonstrate compliance with the SO_2 and NO_X standards.

Net Output. The proposed output-based emission limits for utility boilers are based on gross energy output. To provide a greater incentive for energy efficiency, we would prefer to base output-based emission limits on net-energy output. But, as explained earlier, we are proposing to use gross energy output because a net output approach could result in monitoring difficulties and unreasonable monitoring costs, particularly at facilities with both affected and unaffected units. In general, about 6 to 10 percent of station power is used internally by parasitic loads, but these parasitic loads vary on a source-by-source basis. At some facilities, the use of a net output-based emission limit might be more advantageous. We are considering, therefore, including an optional net output-based emission limit wherever the proposed amendments have an output-based limit. We would develop the limit using a 32 to 34 percent net output efficiency to convert the gross output-based emission limit to a net output-based emission limit. Therefore, we are requesting comments on publishing both a gross output-based emission limit and an optional net output-based emission limit under 40 CFR 60, subpart Da.

Renewable Energy. We are considering adopting a rule provision to recognize the environmental benefits and encourage the installation of non-combustion based renewable electricity generation technologies. We are requesting comments on allowing an affected facility that generates electricity and installs a renewable generation technology (*e.g.*, solar, wind, geothermal, low-impact (small) hydro) to add the electric output from the renewable energy facility to the output of the affected facility when calculating compliance with output-based emission limits. To be eligible, the renewable generation would have to be constructed during the same time period as the affected facility and be located on a contiguous property. This provision could increase compliance flexibility, decrease costs, and contribute to multimedia-pollutant reduction. We are requesting comment on including such a provision in 40 CFR 60, subpart Da and Db, and on what forms of renewable energy would quality.

Definition of Boiler-Operating Day. We are considering amending the definition of boiler-operating day for existing utility units to be consistent with the proposed definition for new units. This would allow 30-day rolling average emission rates to be calculated consistently across sources. We are soliciting comments on if this is appropriate for existing sources.

CEM Availability. In recognition that 40 CFR part 75 requirements are more stringent than the NSPS and provide incentives to keep monitors as close to 100 percent as possible, we are intending to increase NSPS CEM availability. We would like comment on increasing CEM availability from 70 percent to 95 percent under 40 CFR part 60, subpart Da for both existing and new units. Data from EPA's Clean Air Markets Divisions indicates that in 2003 average NO_X hourly CEM availability was 96 percent and average SO_2 hourly CEM availability was 99 percent.

VIII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), we must determine whether the regulatory action is ''significant'' and, therefore, subject to review by OMB and the requirements of the Executive Order. The Executive Order defines ''significant regulatory action'' as one that is likely to result in a action that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that the proposed amendments are a ''significant regulatory action'' because they raise novel legal or policy issues within the meaning of paragraph (4) above. Consequently, the proposed amendments were submitted to OMB for review under Executive Order 12866. Any written comments from OMB and written EPA responses are available in the docket (*see* **ADDRESSES** section of this preamble).

B. Paperwork Reduction Act

The proposed action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* 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 project cost and hour burden made and approved by OMB during the development of the existing standards of performance. Therefore, the information collection requests have not been amended. The OMB has previously approved the information collection requirements contained in the existing standards of performance (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). The OMB assigned OMB control numbers 2060–0023 (ICR 1053.07) for 40 CFR part 60, subpart Da, 2060–0072 (ICR 1088.10) for 40 CFR part 60, subpart Db, 2060–0202 (ICR 1564.06) for 40 CFR part 60, subpart Dc.

Copies of the information collection request document(s) may be obtained from Susan Auby by mail at U.S. EPA, Office of Environmental Information, Collection Strategies Division (2822T), 1200 Pennsylvania Avenue, NW., Washington, DC 20460, by e-mail at *auby.susan@epa.gov,* or by calling (202) 566–1672. A copy may also be downloaded off the Internet at *http://www.epa.gov/icr.*

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

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. 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 (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedures 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 the proposed amendments on small entities, small entity is defined as: (1) A small business according to Small Business Administration size standards by the North American Industry Classification System (NAICS) category of the owning entity. The range of small business size standards for the 17 affected industries ranges from 500 to 750 employees, except for electric utility steam generating units. In the case of utility boilers the size standard is 4 million kilowatt-hours of production or less; (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 that is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's proposed amendments on small entities, we conclude that this action will not have a significant economic impact on a substantial number of small entities. We have determined for electric utility steam generating units, that based on the existing inventory for the corresponding NAICS code and presuming the percentage of entities that are small in that inventory, estimated to be 3 percent, is representative of the percentage of small entities owning new utility boilers in the 5th year after promulgation, that at most, one entity out of five new entities in the industry may be small entities and thus affected by the proposed amendments. We have determined for industrial-commercial steam generating units, based on the existing industrial boilers inventory for the corresponding NAICS codes and presuming the percentage of small entities in that inventory is representative of the percentage of small entities owning new wood-fueled industrial boilers in the 5th year after promulgation, that between two and three entities out of 17 in the industry with NAICS code 321 and 322 may be small entities, and thus affected by the proposed amendments. Based on the boiler size definitions for the affected industries (subpart Db of 40 CFR part 60: greater than or equal to 100 MMBtu/hr; subpart Dc of 40 CFR part 60: 10–100 MMBtu/hr), EPA determined that the firms being affected were likely to fall under the subpart Dc of 40 CFR part 60 boiler category. These two or three affected small entities are estimated to have annual compliance costs between $70 and $105 thousand which represents less than 5 percent of the total compliance cost for all affected wood-fired industrial boilers. Based on the average employment per facility data from the U.S. Census Bureau, for the corresponding NAICS codes under the subpart Db of 40 CFR part 60 and subpart Dc of 40 CFR part 60 categories, the compliance cost of these facilities is expected to be less than 1 percent of their estimated sales. For more information on the results of the analysis of small entity impacts, please refer to the economic impact analysis in the docket.

Although the proposed NSPS would not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of the proposed amendments on small entities. In the proposed amendments, the Agency is applying the minimum level of control and the minimum level of monitoring, recordkeeping, and reporting to affected sources allowed by the CAA. This provision should reduce the size of small entity impacts. We continue to be interested in the potential impacts of the proposed amendments 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 (UMRA) of 1995, Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, we generally must prepare a written statement, including a cost-benefit analysis, for proposed and final actions with ''Federal mandates'' that may result in expenditures by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any 1 year. Before promulgating an EPA action for which a written statement is needed, section 205 of the UMRA generally requires us to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the action. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows us to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if we publish with the final action an explanation why that alternative was not adopted.

Before we establish any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, we must develop a small government agency plan under section 203 of the UMRA. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of our regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We determined that the proposed amendments do 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 1 year. Thus, the proposed amendments are not subject to the requirements of section 202 and 205 of the UMRA. In addition, we determined that the proposed amendments contain 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, the proposed amendments are not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

Executive Order 13132 (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 Executive Order 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.''

Under section 6 of Executive Order 13132, we may not issue a regulation that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or we consult with State and local officials early in the process of developing the proposed action. Also, we may not issue a regulation that has federalism implications and that preempts State law, unless we consult with State and local officials early in the process of developing the proposed action.

The proposed amendments do not have federalism implications. They will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The proposed amendments will not impose substantial direct compliance costs on State or local governments, it will not preempt State law. Thus, Executive Order 13132 does not apply to the proposed amendments.

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

Executive Order 13175, (65 FR 67249, November 9, 2000), requires us to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' ''Policies that have Tribal implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on relationship between the Federal government and the Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes.''

The proposed amendments do not have tribal implications, as specified in Executive Order 13175. They will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to the proposed amendments.

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

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

We interpret Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. The proposed amendments are not subject to Executive Order 13045 because they are based on technology performance and not on health and safety risks. Also, the proposed amendments are not ''economically significant.''

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

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as ''significant energy actions.'' Section 4(b) of Executive Order 13211 defines ''significant energy actions'' as ''* * * any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final action or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) That is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action. * * *''

This action is not a ''significant energy action,'' as defined in Executive Order 13211, because it is not likely to have a significant adverse effect on the supply, distribution, or energy use. Further, we concluded that this action is not likely to have any adverse energy effects.

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, section 12(d)(15 U.S.C. 272 note) directs us to use voluntary consensus standards in our regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, material specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs us to provide Congress, through OMB, explanations when we decide not use available and applicable voluntary consensus standards.

This action does not involve any new technical standards or the incorporation by reference of existing technical standards. Therefore, the consideration of voluntary consensus standards is not relevant to this action.

List of Subjects in 40 CFR Part 60

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

Dated: February 9, 2005.

Stephen L. Johnson,

Acting Administrator.

For the reasons cited in the preamble, title 40, chapter I, part 60 of the Code of 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 60.13 is amended by revising paragraph (h), to read as follows:

§ 60.13 Monitoring requirements

* * * * *

(h)(1) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in § 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period.

(2) For continuous monitoring systems other than opacity, 1-hour averages shall be computed as follows:

(i) For a full operating hour (60 minutes of unit operation), at least four valid data points are required to calculate the hourly average, *i.e.*, one data point in each of the 15-minute quadrants of the hour.

(ii) For a partial operating hour (less than 60 minutes of unit operation), at least one valid data point in each 15-minute quadrant of the hour in which the unit operates is required to calculate the hourly average.

(iii) Notwithstanding the requirements of paragraphs (h)(2)(i) and (h)(2)(ii) of this section, for any operating hour in which required maintenance or quality-assurance activities are performed:

(A) If the unit operates in two or more quadrants of the hour, a minimum of two valid data points, separated by at least 15 minutes, is required to calculate the hourly average; or

(B) If the unit operates in only one quadrant of the hour, at least one valid data point is required to calculate the hourly average.

(iv) If a daily calibration error check is failed during any operating hour, all data for that hour shall be invalidated, unless a subsequent calibration error test is passed in the same hour and sufficient valid data are recorded after the passed calibration to meet the requirements of paragraph (h)(2)(iii) of this section.

(v) For each full or partial operating hour, all valid data points shall be used to calculate the hourly average.

(vi) Data recorded during periods of continuous monitoring system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph.

(vii) Notwithstanding the requirements of paragraph (h)(2)(vi) of this section, owners and operators complying with the requirements of § 60.7(f)(1) or (2) must include any data recorded during periods of monitor breakdown or malfunction in the data averages.

(viii) When specified in an applicable subpart, hourly averages for certain partial operating hours shall not be computed or included in the emission averages (*e.g.* § 60.47b(d)).

(ix) Either arithmetic or integrated averaging of all data may be used to calculate the hourly averages. The data may be recorded in reduced or nonreduced form (*e.g.*, ppm pollutant and percent O_2 or ng/J of pollutant).

(3) All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the applicable subpart. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit (*e.g.*, rounded to the nearest 1 percent opacity).

* * * * *

Subpart D—[Amended]

3. Section 60.45 is amended by revising paragraph (c)(3) to read as follows:

§ 60.45 Emission and fuel monitoring

* * * * *

(c) * * *

(3) For affected facilities burning fossil fuel(s), the span values for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or nitrogen oxides, the span value shall be determined using one of the following procedures:

(i)For affected facilities that are not subject to part 75 of this chapter, SO_2 and NO_X span values determined as follows:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide	Span value for nitrogen oxides
Gas	[1]	500
Liquid	1,000	500
Solid	1,500	1,000
Combinations	1,000+1,500z	500(x+y)+1,000z

[1] Not applicable.

Where:

x = the fraction of total heat input derived from gaseous fossil fuel, and

y = the fraction of total heat input derived from liquid fossil fuel, and

z = the fraction of total heat input derived from solid fossil fuel.

(ii) For affected facilities that are also subject to part 75 of this chapter, SO_2 and NO_X span values determined according to section 2 in appendix A to part 75 of this chapter may be used for the purposes of this subpart.

Subpart Da—[Amended]

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

§ 60.40a Applicability and designation of affected facility.

* * * * *

(b) Heat recovery steam generators that are associated with combined cycle gas turbines burning fuels other than synthetic-coal gas 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 electric utility combined cycle gas turbines that are capable of combusting more than 73 MW (250 MMBtu/hour) heat input of fossil fuel in the heat recovery steam generator. If the heat recovery steam generator is subject to this subpart and the combined cycle gas turbine burn fuels other than synthetic-coal gas, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

* * * * *

5. Section 60.41a is amended by revising the definitions of ''boiler operating day'' and ''electric utility steam generating unit,'' and by adding in alphabetical order the definitions of ''bituminous coal,'' ''coal,'' ''cogeneration,'' ''natural gas,'' and ''petroleum'' to read as follows:

§ 60.41a Definitions.

* * * * *

Bituminous coal means coal that is classified as bituminous according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D38877, 90, 91, 95, or 98a (incorporated by reference—*see* § 60.17).

* * * * *

Boiler operating day for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, boiler operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

* * * * *

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388–77, 90, 91, 95, or 98a, Standard Specification for Classification of Coals by Rank (incorporated by reference—see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

* * * * *

Cogeneration means a facility that simultaneously produces both electrical (or mechanical) and useful thermal energy from the same primary energy source.

* * * * *

Electric utility steam generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. For the purpose of this subpart, net-electric output is the gross electric sales to the utility power distribution system minus purchased power on a 30-day rolling average. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

* * * * *

Natural gas means 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 liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835–82, 86, 87, 91, or 97, ''Standard Specification for Liquid Petroleum Gases'' (Incorporated by reference—see § 60.17).

* * * * *

Petroleum means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

* * * * *

6. Section 60.42a is amended by revising the introductory text in paragraph (a) and adding paragraph (c) to read as follows:

§ 60.42a Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain particulate matter in excess of:

* * * * *

(c) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February

28, 2005, any gases that contain particulate matter in excess of 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

7. Section 60.43a is amended by revising the introductory text in paragraphs (a) and (b) and adding paragraphs (i) and (j) to read as follows:

§ 60.43a Standard for sulfur dioxide.

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain sulfur dioxide in excess of:

* * * * *

(b) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain sulfur dioxide in excess of:

* * * * *

(i) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of 250 ng/J (2.0 lb/MWh) gross energy output, based on a 30-day rolling average, except as provided under paragraph (j) of this section.

(j) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility that burns over 90 percent (by heat input) coal refuse and for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of 300 ng/J (2.4 lb/MWh) gross energy output, based on a 30-day rolling average.

8. Section 60.44a is amended by revising paragraph (d) and adding paragraph (e) to read as follows:

§ 60.44a Standard for nitrogen oxides.

* * * * *

(d)(1) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no new source owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction commenced after July 9, 1997 but before or on February 28, 2005, any gases that contain nitrogen oxides (expressed as NO_2) in excess of 200 ng/J (1.6 lb/MWh) gross energy output, based on a 30-day rolling average, except as provided under § 60.46a(k)(1).

(2) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no existing source owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which reconstruction commenced after July 9, 1997 but before or on February 28, 2005, any gases that contain nitrogen oxides (expressed as NO_2) in excess of 65 ng/J (0.15 lb/MMBtu) heat input, based on a 30-day rolling average.

(e) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no new source owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain nitrogen oxides (expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output, based on a 30-day rolling average, except as provided under § 60.46a(k)(1).

9. Section 60.46a is amended by revising paragraph (i) and adding paragraph (l) to read as follows:

§ 60.46a Compliance provisions.

* * * * *

(i) Compliance provisions for sources subject to § 60.44a(d)(1) or (e). The owner or operator of an affected facility subject to § 60.44a(d)(1) or (e) shall calculate NO_X emissions by multiplying the average hourly NO_X output concentration, measured according to the provisions of § 60.47a(c), by the average hourly flow rate, measured according to the provisions of § 60.47a(l), and dividing by the average hourly gross energy output, measured according to the provisions of § 60.47a(k).

* * * * *

(l) Compliance provisions for sources subject to § 60.43a(i) or (j). The owner or operator of an affected facility subject to § 60.44a(i) or (j) shall calculate SO_2 emissions by multiplying the average hourly SO_2 output concentration, measured according to the provisions of § 60.47a(b), by the average hourly flow rate, measured according to the provisions of § 60.47a(l), and divided by the average hourly gross energy output, measured according to the provisions of § 60.47a(k).

10. Section 60.47a is amended by:

a. Revising paragraph (b)(2);

b. Adding paragraph (b)(4);

c. Revising paragraph (g); and

d. Adding new sentences at the end each of the following paragraphs: (i)(3), (i)(4), and (i)(5) to read as follows:

§ 60.47a Emission monitoring.

* * * * *

(b) * * *

(1) * * *

(2) For a facility that qualifies under the provisions of § 60.43a(d), (i), or (j), sulfur dioxide emissions are only monitored as discharged to the atmosphere.

(3) * * *

(4) If the owner or operator has installed a sulfur dioxide emission rate continuous emission monitoring system (CEMS) to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of § 60.49a. Data reported to meet the requirements of § 60.49a shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

* * * * *

(g) The 1-hour averages required under § 60.13(h) are expressed in ng/J (lb/million Btu) heat input and used to calculate the average emission rates under § 60.46a. The 1-hour averages are calculated using the data points required under § 60.13(h)(2).

* * * * *

(i) * * *

(3) For affected facilities burning only fossil fuel, the span value for continuous monitoring system for measuring opacity is between 60 and 80 percent. For a continuous monitoring

system measuring nitrogen oxides, the span value shall be determined using one of the following procedures:

(i) For affected facilities that are not subject to part 75 of this chapter, NO_X span values determined as follows:

Fossil fuel	Span value for nitrogen oxides (ppm)
Gas	500
Liquid	500
Solid	1,000
Combination	500 (x+y)+1,000z

Where:

x is the fraction of total heat input derived from gaseous fossil fuel,

y is the fraction of total heat input derived from liquid fossil fuel, and

z is the fraction of total heat input derived from solid fossil fuel.

(ii) For affected facilities that are also subject to part 75 of this chapter, NO_X span values determined according to section 2 in appendix A to part 75 of this chapter may be used for the purposes of this subpart.

(4) * * * NO_X span values that are computed under part 75 of this chapter and used for the purposes of this subpart shall be rounded off according to section 2 in appendix A to part 75 of this chapter.

(5) * * * Alternatively, if the affected facility is also subject to part 75 of this chapter, SO_2 span values determined according to section 2 in appendix A to part 75 of this chapter may be used for the purposes of this subpart.

* * * * *

Subpart Db—[Amended]

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

§ 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 million Btu/hour) 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 by adding the definition of ''cogeneration'' in alphabetical order to read as follows:

§ 60.41b Definitions.

* * * * *

Cogeneration means a facility that simultaneously produces both electrical (or mechanical) and useful thermal energy from the same primary energy source.

* * * * *

13. Section 60.43b is amended by adding paragraph (h) to read as follows:

§ 60.43b Standard for particulate matter.

* * * * *

(h) On or 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 particulate matter emissions in excess of 13 ng/J (0.03 lb/million Btu) heat input. Affected facilities subject to this paragraph are also subject to paragraphs (f) and (g) of this section.

14. Section 60.47b is amended by revising paragraph (d) and adding a new sentence at the end of paragraph (e)(3) to read as follows:

§ 60.47b Emission monitoring for sulfur dioxide

* * * * *

(d) The 1-hour average sulfur dioxide emission rates measured by the CEMS required by paragraph (a) of this section and required under § 60.13(h) is expressed in ng/J or lb/million Btu heat input and is used to calculate the average emission rates under § 60.42(b). Each 1-hour average sulfur dioxide emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to § 60.13(h)(2).

Hourly sulfur dioxide emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) * * *

(3) * * * Alternatively, if the affected facility is also subject to part 75 of this chapter, SO_2 span values determined according to section 2 in appendix A to part 75 of this chapter may be used for the purposes of this subpart.

* * * * *

15. Section 60.48b is amended by revising paragraphs (b) introductory text, (d), and (e)(2), and adding a new sentence at the end of paragraph (e)(3) to read as follows:

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

* * * * *

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a nitrogen oxides standard under 60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

* * * * *

(d) The 1-hour average nitrogen oxides emission rates measured by the continuous nitrogen oxides monitor required by paragraph (b) of this section and required under § 60.13(h) shall be expressed in ng/J or lb/million Btu heat input and shall be used to calculate the average emission rates under § 60.44b. The 1-hour averages shall be calculated using the data points required under § 60.13(h)(2).

(e) * * *

(2) For affected facilities combusting coal, oil, or natural gas, the span value for nitrogen oxides shall be determined using one of the following procedures:

(i) For affected facilities that are not subject to part 75 of this chapter, NO_X span values determined as follows:

Fossil fuel	Span value for nitrogen oxides (ppm)
Natural gas	500
Oil	500
Coal	1,000
Mixture	500(x+y)+1,000z

where:

x is the fraction of total heat input derived from natural gas,

y is the fraction of total heat input derived from oil, and

z is the fraction of total heat input derived from coal.

(ii) For affected facilities that are also subject to part 75 of this chapter, NO_X span values determined according to section 2 in appendix A to part 75 of this chapter may be used for the purposes of this subpart.

(3) * * * NO_X span values that are computed under part 75 of this chapter and used for the purposes of this subpart shall be rounded off according to section 2 in appendix A to part 75 of this chapter.

* * * * *

Subpart Dc—[Amended]

16. Section 60.40c is amended by adding paragraph (e) to read as follows:

§ 60.40c Applicability and delegation of authority.

* * * * *

(e) Heat recovery steam generators that are associated with combined cycle gas turbines and 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 or equal to 2.9 MW (10 million Btu/hour) heat input of fossil fuel but less than or equal to 29 MW (100 million Btu/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).

17. Section 60.41c is amended by revising the definition of coal 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 D388–77, 90, 91, 95, or 98a, Standard Specification for Classification of Coals by Rank (IBR—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, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

* * * * *

18. Section 60.43c is amended by adding paragraph (e) to read as follows:

§ 60.43c Standard for particulate matter.

* * * * *

(e) On or 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 particulate matter emissions in excess of 13 ng/J (0.03 lb/million Btu) heat input. Affected facilities subject to this paragraph, are also subject to the requirements of paragraphs (c) and (d) of this section.

19. Section 60.46c is amended by adding a new sentence at the end of paragraphs (c)(3) and (c)(4) to read as follows:

* * * * *

(c) * * *

(3) * * * Alternatively, if the affected facility is also subject to part 75 of this chapter, SO_2 span values determined according to section 2 in appendix A to part 75 of this chapter may be used for the purposes of this subpart.

(4) * * * Alternatively, for affected facilities that are also subject to part 75 of this chapter, SO_2 span values determined according to section 2 in appendix A to part 75 of this chapter may be used for the purposes of this subpart.

* * * * *

Appendix B—[Amended]

20. Appendix B to part 60 is amended by adding a new sentence at the end of section 8.3.1 in Performance Specification 2, to read as follows:

Appendix B to Part 60—Performance Specifications

* * * * *

Performance Specification 2—Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources

* * * * *

8.3.1 * * * Alternatively, the CD test may be conducted over 7 consecutive unit operating days, rather than 7 consecutive calendar days.

* * * * *

Appendix F—[Amended]

21. Appendix F to part 60 is amended by adding sections 4.5 and 5.4, to read as follows:

Appendix F to Part 60—Quality Assurance Procedures

* * * * *

4.5 Alternative CD Assessment. For an affected facility that is also subject to the monitoring and reporting requirements of part 75 of this chapter, the owner or operator may implement 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, instead of the CD assessment procedures in section 4.1 of this appendix. 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 section 4.3 of this appendix.

* * * * *

5.4 Alternative Data Accuracy Assessment. If an affected facility is also subject to the monitoring and reporting requirements of part 75 of this chapter, and if emissions data are reported on a year-round basis under § 75.64 or § 75.74(b) of this chapter, the owner or operator may implement the following alternative data accuracy assessment procedures:

5.4.1 Linearity Checks. Instead of performing the cylinder gas audits described in section 5.1.2 of this appendix, the owner or operator may perform quarterly linearity checks of the SO_2, NO_X, CO_2 and O_2 monitors required by this part, in accordance with section 2.2.1 of appendix B to part 75 of this chapter. If this option is selected:

5.4.1.1 The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; and

5.4.1.2 The applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; and

5.4.1.3 The data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in section 5.2 of this appendix; and

5.4.1.4 The grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply.

5.4.2 Relative Accuracy Test Audits. Instead of following the procedures in section 5.1.1 of this appendix, the owner or operator may perform RATA of the NO_X-diluent or SO_2-diluent CEMS required by this part (or both), in accordance with section 2.3 of appendix B to part 75 of this chapter. If this option is selected for a particular CEMS:

5.4.2.1 The frequency of the RATA shall be as specified in section 2.3.1 of appendix B to part 75; and

5.4.2.2 The applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; and

5.4.2.3 The data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in section 5.2 of this appendix; and

5.4.2.4 The grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply.

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