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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL–6159–2]

RIN 2060–AE56

Revision of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units; Revisions to Reporting Requirements for Standards of Performance for New Fossil-Fuel Fired Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Pursuant to section 407(c) of the Clean Air Act, the EPA has reviewed the emission standards for nitrogen oxides (NO_X) contained in the standards of performance for new electric utility steam generating units and industrial-commercial-institutional steam generating units. The EPA proposed revisions to 40 CFR part 60, subparts Da and Db based on this review on July 9, 1997. The EPA received 70 public comments on the proposed rule changes. These comments were reviewed, and this document reflects the EPA's responses to the issues raised by the commenters. This action promulgates the revised standards of performance.

The final revisions change the existing standards for NO_X emissions by reducing the numerical NO_X emission limits for both utility and industrial steam generating units to reflect the performance of best demonstrated technology. The final revisions also change the format of the revised NO_X emission limit for new electric utility steam generating units to an output-based format to promote energy efficiency and pollution prevention. However, in a change from the proposed language, the EPA is revising the standard for existing utility boilers that become subject to subpart Da through modification or reconstruction to be in an equivalent input-based format.

As a separate activity, the EPA also reviewed the quarterly sulfur dioxide (SO_2), NO_X, and opacity emission reporting requirements of the utility and industrial steam generating unit regulations contained in subparts Da and Db. The final rules will allow owners or operators of affected facilities to meet the quarterly reporting requirements of both regulations by means of electronic reporting, in lieu of submitting written compliance reports.

DATES: *Effective Date:* The rule revisions are effective November 16, 1998.

Judicial Review: Under CAA section 307(b)(1), judicial review of this nationally applicable final action is available only by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of publication of this rule. Under CAA section 307(b)(2), the regulations that are the subject of this action may not be challenged later in civil or criminal proceedings brought by EPA in reliance on them.

ADDRESSES: *Docket:* All information considered by the EPA in developing this rulemaking, including public comments on the proposed rules and other information developed by the EPA in addressing those comments since proposal, is located in Public Docket No. A–92–71 at the following address: U.S. Environmental Protection Agency, Air and Radiation Docket and Information Center (6102), 401 M Street, SW., Washington, DC 20460. The docket is located at the above address in Room M–1500, Waterside Mall (ground floor), and may be inspected from 8:30 a.m. to 4 p.m., Monday through Friday. Materials related to this rulemaking are available upon request from the Air and Radiation Docket and Information Center by calling (202) 260–7548 or 7549. The FAX number for the Center is (202) 260–4400. A reasonable fee may be charged for copying docket materials.

Technical Support Documents. The technical support documents that summarize information gathered during EPA's review of the subparts Da and Db NO_X standards and the public comments and EPA's responses may be obtained from the docket; from the EPA library (MD–35), Research Triangle Park, North Carolina 27711, telephone number (919) 541–2777, FAX number (919) 541–0804; or from the National Technical Information Services, 5285 Port Royal Road, Springfield, Virginia 22161, telephone number (703) 487–4650. Please refer to ''New Source Performance Standards, Subpart Da—Technical Support for Proposed Revisions to NO_X Standard'', EPA–453/R–94–012, ''New Source Performance Standards, Subpart Db—Technical Support for Proposed Revisions to NO_X Standard'', EPA–453/R–95–012, or ''New Source Performance Standards, Subparts Da and Db—Summary of Public Comments and Responses'', EPA–453/R–98–005.

FOR FURTHER INFORMATION CONTACT: For information concerning specific aspects of this rulemaking, contact Mr. James Eddinger, Combustion Group, Emission Standards Division (MD–13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541–5426, electronic mail ''eddinger.jim@epa.gov''.

SUPPLEMENTARY INFORMATION:

Regulated Entities

Regulated categories and entities include:

Category	Examples of regulated entities
Industry	Electric utility steam generating units, Industrial steam generating units, Commercial steam generating units, and Institutional steam generating units.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that the EPA is now aware of that could potentially be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your facility is regulated by this action, you should carefully examine the applicability criteria in §§ 60.40a and 60.40b of the rules. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Electronic Access and Filing Addresses

This document, the regulatory texts, and other background information are available in Docket No. A–92–71 or by request from the EPA's Air and Radiation Docket and Information Center (see **ADDRESSES**) or may be accessed through the EPA web site at: http://www.epa.gov/ttn/oarpg.

Outline

The following outline is provided to aid in locating information in this document.

I. Background

A. Statutory and Regulatory Authority

Title IV of the Clean Air Act (the Act), as amended in 1990, authorizes the EPA to establish an acid rain program to reduce the adverse effects of acidic deposition on natural resources, ecosystems, materials, visibility, and public health. The principal sources of the acidic compounds are emissions of SO_2 and NO_X from the combustion of fossil fuels. Section 407(c) of the Act requires the EPA to revise standards of performance previously promulgated under section 111 for NO_X emissions from fossil-fuel fired steam generating units, including both electric utility and nonutility units. These revised standards of performance are to reflect improvements in methods for the reduction of NO_X emissions.

The current standards for NO_X emissions from fossil-fuel fired steam generating units, which were promulgated under section 111 of the Act, are contained in the new source performance standards (NSPS) for electric utility steam generating units (40 CFR 60.40a, subpart Da) and for industrial-commercial-institutional steam generating units (40 CFR 60.40b, subpart Db).

B. Benefits of the NSPS Revisions

The revisions being promulgated reflect the Administrator's determination that the best system of NO_X emission reduction (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) for these sources is now reflective of flue gas treatment technologies, particularly selective catalytic reduction (SCR). The estimated decrease in baseline nationwide NO_X emissions from new, reconstructed, or modified affected sources resulting from these rule revisions remain unchanged since proposal and are approximately 23,000 Mg/year (25,800 tons/year) from utility steam generating units and 18,000 Mg/year (20,000 tons/year) from industrial steam generating units in the 5th year after proposal. This represents an approximate 42 percent reduction in the growth of NO_X emissions from new utility and industrial steam generating units subject to these revised standards. This reduction in NO_X emissions benefits public health. Nitrogen oxides can cause lung tissue damage, can increase respiratory illness, and are a primary contributor to acid rain and ground level ozone formation. The Agency's estimate of the other environmental, energy, cost, and economic impacts also are unchanged since proposal. (See 62 FR 36957 for more information on these estimates.)

In addition to direct environmental benefits, the EPA believes that the output-based format of the final rule will contribute to important national goals such as pollution prevention. One of the opportunities for pollution prevention lies in simply using energy efficient technologies to minimize the generation of emissions. These revisions promote energy efficiency at utility plants by changing the manner in which they regulate flue gas NO_X emissions. The fuel neutral format of the final rules also contributes to pollution prevention opportunities by encouraging the use of clean fuels without limiting the control options available for compliance.

A third major benefit of these revisions is that the final rules reduce the reporting burden for units subject both to NSPS subpart Da or Db and to other program(s) such as the Acid Rain or NO_X Budget Program. Therefore, the EPA will allow the SO_2, NO_X, and opacity reports currently required under subpart Da or Db to be submitted electronically in lieu of written reports. To implement this electronic reporting option, special electronic data report (EDR) record types would have to be created to accommodate the compliance information required by subparts Da and Db, and sources would be required to obtain an agreement from their EPA Regional office and State authority to use the EDR format. The use of this report form is optional.

C. Public Participation

Prior to proposal, the EPA met with industry representatives several times to discuss the data and information used to develop the proposed revisions. In addition, equipment vendors, State regulatory authorities, and environmental groups had opportunity to comment on the background information that was prepared for the proposed revisions. In addition, representatives from other EPA offices and programs have been included in the regulatory development process as members of the Work Group.

The proposed revisions were published in the **Federal Register** on July 9, 1997 (62 FR 36948). The preamble to the proposed revisions discussed the availability of technical support documents, which described in detail the information gathered during the standards review. Public comments were solicited at proposal.

To provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standards, a public hearing was held on August 8, 1997, at Research Triangle Park, North Carolina. However, the four scheduled speakers decided to submit written comments in place of attending the hearing, so no information was presented at the hearing.

The original public comment period was from July 9, 1997 to September 8, 1997. The EPA extended the public comment period to October 8, 1997 based on requests from commenters. During the public comment period, the EPA received 70 public comment letters on the proposed rule changes. In the post-proposal period, the EPA met with several industry representatives to learn more of their concerns regarding the proposed revisions and to gather additional information in order to respond to the public comments. Records of these contacts are found in the final rulemaking docket. All of the comments have been carefully considered, and, where determined to be appropriate by the Administrator, changes have been made in the proposed standards based on the comments received.

II. Summary of Final Rules

The final standards revise the NO_X emission limits for steam generating units in subpart Da (Electric Utility Steam Generating Units) and subpart Db (Industrial-Commercial-Institutional Steam Generating Units). Only those electric utility and industrial steam generating units for which construction, modification, or reconstruction is commenced after July 9, 1997 would be affected by these revisions.

The NO_X emission limit in the final rule for newly constructed subpart Da units is 200 nanograms per joule (ng/J_O) (1.6 lb/megawatt-hour (MWh)) gross energy output regardless of fuel type. For existing sources that become subject to subpart Da through modification or reconstruction, the NO_X emission limit is 65 ng/J_I [0.15 pounds per million BTU (lb/MMBtu)] heat input. For subpart Db units, the NO_X emission limit being promulgated is 87 ng/J_I (0.20 lb/MMBtu) heat input from the combustion of natural gas, oil, coal, or a mixture containing any of these fossil fuels; however, for low heat release rate units firing natural gas or distillate oil, the current NO_X emission limit of 43 ng/J_I (0.10 lb/MMBtu) heat input is unchanged.

Compliance with the proposed NO_X emission limit is determined on a 30-day rolling average basis, which is the same requirement that was in effect prior to the revisions. The EPA has added compliance and monitoring provisions that explain how sources are to demonstrate compliance with the output-based standards. These provisions will not increase the overall burden of sources to demonstrate compliance with the standards beyond what is already required of sources in the absence of these changes.

The revisions to the quarterly SO_2, NO_X, and opacity reporting requirements of subparts Da and Db allow electronic quarterly reports to be submitted in lieu of the written reports currently required under §§ 60.49a and 60.49b. The electronic reporting option would be available to any affected facility under subpart Da or Db, including units presently regulated under those subparts. Each electronic quarterly report would be submitted no later than 30 days after the end of the calendar quarter.

The format of the electronic report would be coordinated with the permitting authority. Each electronic report would be accompanied by a certification statement from the owner or operator indicating whether compliance with the applicable emission standards and minimum data requirements was achieved during the reporting period. Owners or operators would also be required to coordinate with their EPA Regional Office and State authority to ensure that the permitting authority agrees to receive reports in the EDR format.

The EPA has determined that acid rain continuous emissions monitoring systems (CEMS) can be used as NSPS CEMS. However, all CEMS must generate reports according to the requirements of the applicable subpart. For example, the acid rain CEMS missing data procedures are not acceptable under subpart Da. Under subpart Da, emission limits during hours of invalid data must be met according to the requirements of § 60.47a(f), which would supersede the acid rain CEMS procedures.

III. Significant Comments and Changes to the Proposed Revisions

Following is a discussion of the significant comments received on the proposed revisions and the resulting changes, if any, in the final rules. The document, ''New Source Performance Standards, Subparts Da and Db—Summary of Public Comments and Responses'' (EPA 453–R–98–005) contains a more detailed summary of all of the comments and responses. It also contains the explanation for minor editorial corrections made in the final revisions.

A. Performance of NO_X Control Technology

1. Selective Catalytic Reduction (SCR)

Several commenters raised concerns that the EPA's determination that SCR represents the best demonstrated technology (BDT) is not adequate. For example, commenters stated that the EPA should not consider SCR as BDT for coal-fired industrial boilers, because it has only been installed on 7 coal-fired units in the U.S., all of which are electric utility units. In addition, none of the 200 European and Japanese units with SCR cited by the EPA are industrial units. Commenters also urged that the EPA consider the potential problems associated with SCR, including costs, catalyst poisoning, and oil ash coating the catalyst, when finalizing the NSPS. Another technical issue raised was that excess SO_3 can lead to increased downstream corrosion and negative impacts on the heat rate of the unit.

Commenters also said that the relevant technologies are immature, and that EPA has insufficient data to develop a standard that fully accounts for the variabilities inherent in operating these new technologies. Other commenters added that the reported cases of successful SCR applications are extremely limited, with success being measured on the basis of short-term performance and without cost considerations.

Commenters raised similar concerns for coal-fired utility boilers. That is, they said the technology is still in the developmental phase, and there are insufficient cases where the performance of the technology has been adequately demonstrated.

The first issue raised by several of the commenters is that EPA's determination that SCR represents BDT for a range of boiler types and operating conditions is not adequate. The EPA disagrees and believes the data base that supports the BDT decision is adequate for two reasons. First, the proposal data base resulted from an extensive review of information on the available domestic and international SCR units in use in the industry at the present time. However, in response to the comments, the EPA has obtained data from three more utility boilers that utilize SCR and represent a range of operating conditions and coal types. The first utility boiler (U.S. Generating Company's Logan plant) is a 225-megawatt pulverized-coal cogeneration facility, and is operated under cycling conditions. This facility submitted 3 months of NO_X emission data to the EPA. The analysis of these data indicate that the facility is capable of achieving the input-based NO_X standard of 65 ng/J_I (0.15 lb/MMBtu) and the revised output-based standard of 200 ng/J_O (1.6 lb/MWh) gross energy output on a 30-day rolling average. (See section III.B.3 for a discussion of the development of the revised output-based standard.) The second plant is the Birchwood Power Facility, which is a 240-megawatt cogeneration facility with cycling load that began operation in 1996. Actual, short-term test results show that the facility achieves NO_X emissions of 97 ng/J_O (0.77 lb/MWh), easily attaining the NSPS output-based standard. The third facility, Stanton Energy, is a 464-megawatt utility boiler firing bituminous coal. This facility is currently meeting its permitted emission limit of 74 ng/J_I (0.17 lb/MMBtu). If this facility were to improve the performance of its SCR to 65 ng/J_I (0.15 lb/MMBtu), this facility would be capable of meeting the 200 ng/J_O (1.6 lb/MWh) output-based limit.

Second, the data base is adequate to evaluate the factors that can potentially affect SCR performance in a wide range of operating conditions. Fundamentally, like all post-combustion control devices, SCR is designed to respond to the characteristics of the stack gas. The primary difference between utility and non-utility boiler types may be that, on average, non-utility boilers may be more likely to operate with fluctuating loads. This difference in operating pattern may appear to have an impact on the characteristics of the stack gas. However, the NSPS is based on a 30-day averaging period to accommodate normal fluctuations in performance. Further, as discussed above, new analyses of two facilities that operate under cycling conditions have shown that SCR can meet the revised standard over a 30-day averaging period. The Birchwood facility reports daily cycle variations from 32 percent to 100 percent of load. The Logan facility's daily cycles ranged from 28 percent to 84 percent in the 3-month period for which data were supplied.

Another load-related technical issue raised is the difficulty in maintaining the temperatures necessary to minimize NO_X and HAP generation. In general, while designing an SCR system for a boiler, the boiler duty is taken into consideration. Specifically, the expected temperature range at the exit of the economizer is factored in the selection of an SCR catalyst formulation.

There are other steps that operators can take to ensure the desired SCR performance under variable or low load conditions. For example, if low load contributes to insufficient gas velocity to keep the flyash in suspension, the operator can add an ash hopper to divert the ash from the reactor and catalyst face. Alternatively, good ductwork system design can avoid these problems. Also, low boiler exit temperatures can be avoided by adding a economizer by-pass to keep the gas temperature higher at low loads. Finally, good flue gas mixing can overcome differences in gas flows and boiler firing conditions. Taking into consideration all of the above, in general, the EPA does not believe that SCR use is constrained by boiler duty.

Several commenters raised catalyst poisoning as an illustration that SCR is not suitable for all units. As a result of developments in catalyst technology, formulations are currently available that minimize the impact of poisoning. Nevertheless, the EPA believes this issue is really related to the cost of operating the SCR; appropriate catalyst management plans now make it possible to maximize catalyst life under plant operating conditions.

Another issue raised by commenters is that the SCR technology is immature and insufficiently demonstrated. The EPA disagrees with this comment. One recent study (Khan, S., *et al.*, ''SCR Applications: Addressing Coal Characteristic Concerns.'' Presented at the EPRI–DOE–EPA Combined Utility Air Pollutant Control Symposium, August 1997) identified at least 212 worldwide SCR installations on coal-fired units, which cover different types of boilers subjected to varying operating conditions and firing a variety of coals. Some of these installations were designed for and have achieved high NO_X reduction levels, exceeding 90 percent. Plants in Europe have been continuously using SCR for over 10 years. Finally, SCR-equipped units located in the U.S., such as the Logan, Birchwood, and Stanton facilities, are meeting some of the most stringent NO_X limits in the country.

2. Coal-related Issues

Several commenters expressed their concern that the proposed NSPS are not adequately demonstrated for all U.S. coals, particularly medium- and high-sulfur coals. They said that German and Japanese experience with these coals is undocumented, or, in the case of Japan, is with SCRs using hot-side electrostatic precipitators (ESPs) in a low-dust environment, compared to most U.S. boilers, which use cold-side ESP's in a high-dust environment. The commenters also rejected the Department of Energy Plant Crist high-sulfur coal demonstration project because of its limited scope.

The EPA disagrees that the use of SCR for high-sulfur coal applications is unsupported. In addition to one coal-fired plant in Japan and another in Austria firing coals with sulfur contents of 2.5 percent or higher, there are two coal-fired SCR installations in the U.S. that are firing coals with sulfur contents close to 2 percent. The Northampton generating facility, which is equipped with SNCR, successfully burns waste coal, and meets some of the most stringent NO_X limits in the U.S. (0.10 lb/MMBtu). In the Plant Crist demonstration project, the catalysts from various suppliers performed successfully. Criteria for successful performance at this demonstration included ammonia slip less than 5 ppm and SO_2 oxidation less than 0.75 percent.

In view of the experience both in the U.S. and abroad, the commenters' concerns over the use of SCR for high-sulfur coal applications is unsupported. In general for these installations, design features such as low ammonia slip, a catalyst that minimizes SO_3 conversion, and an economizer bypass to maintain proper flue gas temperatures at low loads are provided.

3. Selective Noncatalytic Reduction (SNCR)

Other commenters argued that SNCR was not adequately demonstrated on fluidized bed combustion boilers (FBCs) and/or large boilers. One commenter noted that the EPA's data showed that three of the five circulating FCBs that use SNCR stated that SNCR did not work properly when the units were operated at anything less than maximum capacity. Another commenter said SNCR ''has not been adequately demonstrated to work on large boilers (with a rated capacity greater than 390 MMBtu/hr), whether circulating bed or not.''

Flue gas temperatures exiting the furnace can range from 1,200 °C ± 110 °C (2,200 °F ± 200 °F) at full load down to 1,040 °C ± 70 °C (1,900 °F ± 125 °F) at half load. At similar loads, temperatures can increase by as much as 30 to 60 °C (50 to 110 °F) depending on the extent of ash deposition on heat transfer surfaces. Due to these variations in the temperatures, it is often necessary to inject the reagent at different locations or levels in the upper furnace or convective pass for effective NO_X reduction. A recent publication summarized the successful retrofit of retractable lances on a 100-megawatt coal-fired utility boiler equipped with SNCR, which greatly improved low load performance. Finally, the addition of hydrogen or other hydrocarbon reducing agent can be injected with the ammonia to lower the effective temperature range. Similarly, additives can increase the temperature range of urea application. By taking these sorts of steps, the EPA believes that operators can successfully operate SNCR, even under low load conditions.

Recent analysis of NO_X emissions data from a 110-megawatt, base-loaded, circulating fluidized-bed boiler equipped with SNCR (U.S. Generating Company's Northampton plant) indicates that the facility is quite capable of meeting the proposed standard. This facility achieves average input-based emissions of 38 ng/J_I (0.089 lb/MMBtu) and output-based emissions of less than 100 ng/J_O (0.8 lb/MWh), well below the output-based standard of 200 ng/J_O (1.6 lb/MWh) gross energy output.

Regarding SNCR on large boilers, the Acid Rain Phase II NO_X Response to Comments Document (p. 212) notes that SNCR has been demonstrated on coal-fired units as large as 1,230 MMBtu/hr (Germany) and on oil-fired units as large as 2,900 MMBtu/hr (Niagara Mohawk's Oswego Station). The SNCR application on Oswego shows that injectors can effectively penetrate the combustion gas flow in large boilers. Since the effectiveness of injecting SNCR reagent into large boiler casings has been proven, and SNCR has been applied to a variety of boilers, the EPA does not see boiler size as a restriction for applying SNCR to NSPS sources.

B. Regulatory Approach

1. Fuel Neutral Approach

Several commenters supported a cap on NO_X emissions at the same level for nearly all fuel types, because it allows fuel switching as a control technology and is an ''important and positive step toward cleaner air . . . across the nation.'' Commenters stated that currently, natural gas-fired units are subject to the most stringent standard while coal and residual oil are allowed to emit much larger quantities of NO_X. The proposed rule will remove any disincentive toward natural gas that has been created by this situation. One commenter wrote that a fuel neutral standard would not penalize any particular industry, but would encourage competition for new efficient boilers and cogeneration units, and would be consistent with the EPA's emphasis on pollution prevention.

Other commenters opposed the same NO_X emission limit for all fuel types arguing that it sets a lower than lowest achievable emission rate (LAER) and best available control technology (BACT) level for coal-fired boilers, while significantly relaxing standards for natural gas units by a factor of two to four times. Another commenter stated that a number of gas- and oil-fired units in the U.S. currently achieve approximately one-tenth of the proposed limit with the application of SCR.

Commenters stated that the ''proposal violates the Act by providing an overwhelming incentive for new and modified electric generating units to burn natural gas to the exclusion of coal.'' Other commenters opposed the fuel neutral approach because of fuel availability and cost factors. One commenter stated that natural gas is not uniformly distributed and evenly available to all industrial users. The commenter asserted that the proposed emission limit ''favors industrial development in regions that have an ample supply of natural gas and penalizes regions that have no practical option for steam production at industrial facilities other than coal.''

One commenter said the fuel neutral emission rate may inadvertently be a dis-benefit to the introduction of low NO_X technology. The commenter postulated that ''the result then might be continued operation of older more polluting sources than might otherwise occur.''

The EPA disagrees with the commenters who contend that the fuel neutral format creates an overwhelming or disproportionate incentive to use fuels other than coal. The EPA's approach is designed to allow the continued use of coal as a fuel in those cases where it is desirable. The standard would, however, also not discourage conversion to natural gas where it makes sense in the individual application.

The EPA believes the fuel neutral approach will expand the control options available by allowing the use of clean fuels as a method for reducing NO_X emissions. Since projected new utility steam generating units are predominantly coal-fired, the use of clean fuels (i.e., natural gas) as a method of reducing NO_X emissions from these coal-fired steam generating units may give the regulated community a more cost-effective option than the application of SCR for meeting the NO_X limit. Similarly, for industrial units, the use of clean fuels as a method of reducing emissions may be a cost-effective approach for coal-fired and residual oil-fired industrial steam generating units.

The fuel neutral approach also fits well with section 101(a)(3) of the Act's emphasis on pollution prevention, which is one of the EPA's highest priorities. Because natural gas is essentially free of sulfur and nitrogen and without inorganic matter typically present in coal and oil, SO_2, NO_X, inorganic particulate, and air toxic compound emissions can be dramatically reduced, depending on the degree of natural gas use. With these environmental advantages, gas-based control techniques should be viewed as a sound alternative to flue gas treatment technologies for coal or oil burning.

Finally, the proposed amendments do not relax the existing NSPS for natural gas units. In fact, the 65 ng/J_I (0.15 lb/MMBtu) heat input reflects a 50- and 25-percent reduction in NO_X emissions over the current subpart Da limits for oil-fired and gas-fired units, respectively. Revised subpart Db would not require any additional controls for new gas-fired and distillate oil-fired units over the current NSPS because of the costs associated with additional controls. However, subpart Db does not relax the existing standards for these units either.

2. Output-Based Format to Subpart Da

Several commenters supported the output-based format of the proposed subpart Da standard, because they felt it would reward energy-efficient generators. However, other commenters opposed the format for the following reasons:

(1) The incentives to be efficient have recently increased due to the newly competitive nature of the industry, and will continue to increase without output-based standards.

(2) The format would add significant burdens to an already complicated monitoring system for utilities.

(3) There are inconsistencies between the proposed NSPS output-based format and several other input-based regulations that are also applicable to these sources.

(4) NO_X averaging of NSPS units with existing units would be very complicated.

(5) The output-based format is inappropriate and inaccurate for cogeneration facilities that produce steam in addition to or in place of electric generation. Because the customers dictate the temperature and pressure conditions of the steam that is produced, the generator has no choice and must produce the desired product. In addition, the EPA method of equating steam production to electric production was over-simplified and punitive in that it does not consider all of the potential steam production conditions, and it would increase the cost of efficient cogeneration.

(6) An output-based NSPS does not promote energy efficiency because it ''makes no allowance for the use of low Btu fuels (such as waste coal) that would otherwise go unused,'' which would increase the costs of electrical generation and discourage national energy self-sufficiency. Further, the proposed NSPS is inconsistent with recent utility deregulation, because ''an important goal of recent utility de-regulation was to allow market forces to minimize the cost of electric power to consumers, without eroding environmental protection.''

The EPA continues to believe in the benefits associated with an output-based standard for new sources that encourages energy efficiency. As discussed in section III.C, however, the EPA has revised the final standard for existing sources that become subject to the NSPS because of modification or reconstruction, to be in the equivalent input-based format of 65 ng/J_I (0.15 lb/MMBtu).

The changes in the output-based format, discussed below in section III.B.3, will simplify the compliance demonstration for sources by eliminating the need to convert input values to output values. Given that the output-based format is a new regulatory approach for these sources, it is inevitable that some inconsistencies in monitoring requirements associated with various programs to which individual sources might be subject would occur. While the EPA is concerned about these apparent inconsistencies, the EPA also feels that the requirements of the NSPS stand on their own merits. The NSPS provisions do not require any new monitoring at sources that is not already required by some other program (i.e., the Acid Rain program.) However, in some instances, the Title V permit process and activities such as permit streamlining may provide relief to sources on a case-by-case basis. In addition, the EPA will continue to explore additional ways to provide monitoring relief that do not compromise the ability of EPA to adequately enforce Federal standards.

As discussed below in section III.B.3, the EPA did examine possible revisions to the steam credit allowance for cogeneration facilities. These issues are further addressed in that section.

Finally, the EPA believes that low-cost fuels can be used effectively at facilities subject to the final standards. As discussed, the U.S. Generating

Company's Northampton facility is currently performing better than would be required under the amended NSPS and uses waste coal as its sole energy source.

3. Input to Output Conversion Assumptions

The EPA revised the approach used to develop the output-based limit based on analysis of comments submitted on the input to output conversion assumptions relied on in developing the proposed standard. As discussed in detail in this section, the EPA will finalize the standard for new sources at a level of 200 ng/J_O (1.6 lb/MWh) gross energy output. The revised standard contained in this final rule is based on actual measured energy output, rather than measured heat input converted to energy output, as was the case with the proposed standard. This change addresses concerns related to overall heat rates, steam credits for cogeneration facilities, and gross versus net output. The key underlying assumption inherent in the selection of the level of the final standards at 200 ng/J_O (1.6 lb/MWh) gross output, i.e., the input-based standard of 65 ng/J_I (0.15 lb/MMBtu), is maintained.

38-Percent Baseline Efficiency. There were comments both in support of and opposed to the selection of an average 38-percent baseline boiler efficiency. The selection of a baseline efficiency value is intimately tied to the selection of a corresponding heat rate. Based on data available since the proposed standards, the Agency has been able to evaluate heat rate directly.

9,000 Btu/kWh Heat Rate. The majority of commenters opposed the selection of an assumed 9,000 Btu/kWh heat rate for use in converting input-derived NO_X emissions to an output basis. Several commenters provided examples of units that operate in the 10,000 to 11,000 Btu/kWh range. The commenters indicated that net heat rates of 10,000 to 10,500 Btu/kWh are typical of state-of-the-art units.

In light of additional data supplied by commenters and collected by EPA, the EPA has decided to revise the assumed heat rate. First, as explained later, the output-based standard is now based on gross output instead of net output, so the following discussion will be in terms of gross heat rates.

The EPA collected data from four additional utility boilers that are considered to be new and state-of-the-art from an emissions standpoint. The first boiler is a base-loaded, fluidized bed combustion cogeneration unit that fires waste coal and is equipped with SNCR (Northampton). This unit's average gross heat rate (with 50 percent credit for export steam) is less than 9,000 Btu/kWh. The second unit is a pulverized coal-fired, cogeneration unit that operates under cycling load and is equipped with SCR (Logan). This unit's average gross heat rate (with 50 percent credit for export steam) is approximately 10,250 Btu/kWh. The third utility boiler (Stanton) has an average heat rate of 10,250 Btu/kWh. The Birchwood cogeneration unit, the fourth facility, reported that they cycle between heat rates of approximately 10,700 Btu/kWh at 32 percent load and 9,000 Btu/kWh at 100 percent load. The heat rates reported by the Birchwood cogeneration unit are based on a 100 percent credit for export steam.

The EPA conducted statistical analyses in which the objective was to assess long-term NO_X emission levels, on an output basis, that can be achieved continuously. Statistically, Logan, Northampton, and Birchwood all can meet the revised output-based standard of 200 ng/J_O (1.6 lb/MWh) (gross) on a 30-day rolling average.

Cogeneration Steam Credit. Several commenters asserted that using only 50 percent of the thermal energy from the steam generated at cogeneration facilities in calculations of output-based emission rates is inappropriate. The commenters reported that the 50-percent allocation is from a section of the Public Utility Restructuring Policy Act (PURPA) in which the 50-percent thermal output is used as part of a definition of a PURPA-qualifying facility. Basing the NSPS on this factor is not justified according to the commenters. The commenters also suggested a variety of ways to calculate the steam credit including (1) converting the electric output to MMBtu plus the enthalpy of the full steam or hot water output in MMBtu, or the electric output in MWh_{el} plus the enthalpy of the full steam or hot water output in MWh_{th}, (2) measuring pounds of NO_X per million Btu of steam produced at the boiler steam header, or (3) measuring the electric output plus the full thermal output in consistent units. Another commenter suggested that since each application would differ in efficiency, credit should be given for the heat actually used and calculated on a case-by-case basis.

Other commenters insisted that efficiency should not be used as a compliance measure. The commenter explained that the efficiency calculation is an extra, unneeded step. The commenters reported that all that is needed is a CEMS to directly measure NO_X and an electric or thermal measurement for output in units of MMBtu or MWh.

As discussed, the EPA has revised the form of the final standards to be based on a direct measure of output, i.e., mass of NO_X per unit of gross energy output. In order to evaluate the data supporting the level of the standard, the EPA had to conduct data analysis to address the level of steam credit for cogeneration facilities. The EPA considered three approaches for addressing the issue of steam credit for cogeneration facilities: (1) Allow credit for steam as if it were being converted into electricity; (2) Allow credit in the form of 50 percent of the thermal value (enthalpy) of the steam; and (3) Allow credit for greater than 50 percent of the value of the steam, up to 100 percent.

The EPA decided not to allow credit for steam as if it were being converted into electricity because the EPA wants to encourage cogeneration. Allowing credit as if electricity would only provide credit for up to 38 percent of the value of the steam, which is the reported maximum of the efficiency of steam to electricity conversion.

The EPA also decided not to allow for greater than 50-percent credit for the steam. Based on analysis of heat rates for cogeneration facilities, the EPA has determined that once a facility exceeds 50 percent and approaches 100 percent credit for the steam, there is a potential for calculating an artificially high output rate, particularly if much of the steam is exported. As another option, the EPA considered allowing 100 percent credit for steam, but capping the amount of steam for which credit could be received to a certain percentage of total output. This approach was deemed to be too complex from a monitoring standpoint.

Therefore, the EPA retained the proposed 50-percent credit for export steam from cogeneration facilities on the basis that it encourages cogeneration, will not result in artificially high output rates, and will not require complex monitoring. This outcome is based on the information available to the Agency at this time. We recognize, however, that cogeneration increases the efficiency of power generation and, as discussed above, comments received during the rulemaking process indicate that there may be alternative ways of calculating the value of thermal output that warrant further consideration. We are interested in exploring alternative approaches to cogeneration and request further comment on this issue. We particularly are interested in hearing about alternatives that would allow us to determine the fraction of the energy delivered to the industrial process that is actually used and should, therefore, be included in the calculation of the gross output from cogeneration facilities.

Gross Versus Net Output. While some commenters support the use of a net output basis to the final format of the standard because it encourages energy efficiency at the facility, several other commenters raised concerns regarding how net output would actually be measured in the industry. One commenter reported that the output-based format would ''require significant and costly changes to the software of monitoring and reporting systems.'' Other commenters reported that electrical output cannot be measured directly because it is dependent on the ''electrical usage by hundreds of motors and other auxiliary equipment located throughout the plants.'' They claimed that net generation cannot be measured ''by simply installing a wattmeter.''

One commenter recommended basing the standards on gross rather than net output to account for the power drain associated with many types of control technologies. Other commenters protested that the proposal did not include a specific methodology for determining the unit net output. They said the EPA did not provide for a subsequent comment period on a ''significant component'' of the proposal, and the EPA should withdraw the proposal until a complete and thorough package can be provided for full public review and comment.

The EPA has reconsidered its position, and has decided to finalize the rule based on the use of gross output because of the monitoring difficulties inherent in the net output methodology. In particular, measuring net output at facilities with both affected and nonaffected units could be problematic, because a single meter on the electricity leaving the facility could not effectively allocate the electricity leaving the affected boiler. The EPA may revisit this issue should EPA develop a methodology to determine the net heat output in all circumstances.

C. Modification and Reconstruction

Commenters expressed opposition to the applicability of the NSPS to modified units. They said that Congress' intent in developing the NSPS program was to limit applicability to sources that could be designed to include state-of-the-art pollution control technology, and that the emphasis on new sources reflected Congress' recognition of the difficulty and expense of retrofitting control technology on existing sources.

One commenter said that the EPA was ''acting unlawfully by failing to consider the costs that will be incurred by existing sources that become the subject of the proposed NO_X standard.'' The commenter proffered that existing coal-fired sources are likely to become subject to this rule eventually, unless they are specifically excluded. According to this commenter, if this occurs, the existing sources will be faced with excessive retrofit costs in order to attain the standard.

One commenter stated that ''the installation of SCR on existing units * * * would be economically infeasible.'' A possible solution proposed by a commenter was that the EPA propose a standard that modified units could meet without SCR, or justify the use of the same standards as for new units. One commenter reasoned that ''since EPA states that few modified sources will be affected, adding specific language clarifying that such units are not subject to the NSPS would raise few, if any, policy implications.'' Another possible solution presented was that the EPA specifically exclude modified boilers from the final NSPS.

One commenter stated that the proposed NO_X emission limit was not demonstrated for non-gas-fired modified sources and that the new limit should not apply to sources that come under the NSPS through modification. In situations where liquid or solid fuel is fired, it is not always possible or reasonable to comply with the proposed limit. For instance, the commenter has a residual oil-fired boiler that could not be retrofitted to meet the proposed standard, and add-on controls would not be feasible because of limited space and unreasonable cost.

One commenter said EPA is aggressively pursuing businesses that have made efficiency improvements to force the units to meet NSPS under the modification provisions in 40 CFR part 60. The commenter stated that the EPA ''clearly has the discretion and duty to distinguish between new and existing sources which become subject to this rule.''

The Clean Air Act defines a modification as ''any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.'' (Section 111(a)(4)) Section 60.14 of the subpart A General Provisions provides additional guidance on EPA's interpretation of this definition, and specifically excludes changes in ownership of an existing facility from being considered a modification. (40 CFR 60.14) In addition, a key aspect to the definition of modification is that the change to the facility must result in an emissions increase.

Section 111(b)(1)(B) of the Act requires the Administrator to promulgate standards of performance for ''new sources'' in each category of sources which in the Administrator's judgment causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. Section 111(a)(2) of the Act defines ''new source'' to include stationary sources which are modified after an applicable standard of performance is proposed. The EPA finds nothing in the comments that would justify ignoring this clear statutory mandate. In developing standards of performance, section 111(a)(1) of the Act does, however, allow the Administrator to take into consideration the cost of achieving the required reduction and any nonair quality health and environmental impact and energy requirements. As noted at proposal, the efficiency of most existing electric utility steam generating plants ranges from 24- to 38-percent efficient. The EPA selected 38-percent efficiency as the baseline reflective of NSPS units. The EPA believes that selecting the 38-percent efficiency level for new electric utility steam generating units was an appropriate exercise of its discretion based on the available information. The EPA realizes, however, that existing units are likely to operate in the lower end of this range, with higher associated heat rates, which would make it more difficult to meet an output-based standard. These sources would have to compensate with higher control device performance (up to a 40-percent increase in performance), which would be more costly. To ease this potential burden, the EPA has decided to allow any existing units that become subject to the NSPS as a result of undergoing a modification or reconstruction to meet the equivalent input-based standard of 65 ng/J_I (0.15 lb/MMBtu) on which the output-based standard applicable to new units is based. This change will eliminate the concern that higher average heat rates at existing units could adversely affect a source's ability to meet an output-based standard. This level of control represents the same overall level of SCR performance that would be required of new units, but lacks the benefits attributed to promoting energy efficiency that the output-based format provides.

D. Applicability and Exemptions

1. Gas Turbines

Commenters stated that the EPA should not apply the proposed standard to modified and reconstructed waste heat boilers. The commenters said these waste heat systems are typically installed in the ductwork of a gas turbine exhaust and are not amenable to significant modification for NO_X control because of their configuration. According to the commenters, tubes are tightly packed, space for reconfiguration is extremely limited, and possible back pressure impacts on the upstream device are a major concern. Applying the NSPS would require the combined system to meet the new standard, because the NO_X from the upstream device (i.e., combustion turbine) cannot be separated from the steam generator NO_X for purposes of add-on control. The commenters said that add-on controls are not demonstrated for such systems.

The systems described by the commenters would be subject to subpart GG of this part, standards of performance for stationary gas turbines, and subparts Da or Db. Because these standards cover separate emission sources, continued applicability of subparts Da or Db is needed. However, the EPA's ongoing Industrial Combustion Coordinated Rulemaking (ICCR) could result in the EPA extending the applicability of subpart GG to the duct burner, which is currently covered by subparts Da and Db. The EPA agrees that if this were to occur, the ICCR-driven revisions to subpart GG would pose a potential conflict with the subparts Da and Db. Therefore, the EPA will revise subparts Da and Db to exempt sources that may also become subject to subpart GG, should such revisions to subpart GG occur.

2. Ten-Percent Exemption

Commenters noted that the proposed revision appears to apply to all steam generating units, including units that are excluded from the current standard because they fire 10 percent or less fossil fuel. The commenters did not believe that the EPA intended that the revised NO_X limit should apply to facilities that combust a limited amount of fossil fuel. Several commenters suggested clarifying the following language at the end of § 60.44b(l)(1): ''* * * 86 ng/J_I (0.20 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or * * *.''

The EPA did not intend to remove the 10-percent exemption from the revised NSPS. The EPA will add the suggested regulatory language to clarify that this exemption still applies.

3. Municipal Waste Combustors

Commenters pointed out that, as written, the proposed NO_X revisions would include municipal solid waste combustors (MWC) that only use a limited amount of fossil fuels for startup purposes and supplemental fuel during those periods when the heat content of the waste is low, in order to maintain good combustion conditions. These units are already subject to subpart Eb of this part, the revised NSPS for large MWC. The commenters suggested that the addition of the 10-percent exemption, discussed above, would alleviate this concern or that exemptions for MWC units subject to the relevant MWC rules would make sense.

As discussed above, the EPA has included the language regarding the 10-percent exemption to the final rule, which should cover these types of sources. In addition the EPA will revise the final rule to exempt units that are subject to subpart Eb to avoid any possible conflicts.

E. Monitoring

Several commenters requested that the EPA clarify and expand the allowance of the use of part 75 CEMS in place of the subparts Da and Db required monitoring provisions. In particular, commenters requested that part 75 elements such as data validation procedures, CEMS configuration specifications, and methods of compliance determination should be deemed to satisfy subparts Da and Db monitoring provisions.

In the past, the EPA determined that Acid Rain CEMS can be used as NSPS Subpart Da CEMS. That determination is available on the Office of Enforcement and Compliance Assurances's web site. A subpart Db boiler equipped with an acid rain CEMS can also use this CEMS as a subpart Db CEMS. In either case, the reports generated by this CEMS must be generated according to the provisions of subparts Da or Db, as applicable, and submitted to the authority in charge of the NSPS program, because the NSPS and acid rain programs have different requirements and are managed by different authorities.

Regarding data validation procedures, the EPA headquarters already maintains the acid rain data base and the AIRS data base, which is suitable for reports from non-acid rain programs. In addition, several States maintain their own data bases. The EPA believes that the data validation issue should not lead to any conflicts considering that the acid rain and the subparts Da and Db report formats must follow their own requirements. The EPA headquarters has addressed a few span-related issues upon request and will continue this practice under the part 60 General Provisions. Finally, emission limits during hours of invalid data must be met using other means than CEMS data according to the requirements of § 60.47a(f) or § 60.48b(f), as applicable.

The EPA has added language to § 60.47a(c) to clarify that ''If the owner or operator has installed a nitrogen oxides 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. Similar language has also been added to § 60.48b(b) to clarify the use of part 75 CEMS with subpart Db affected facilities.

IV. Administrative Requirements

A. Docket

This final rulemaking action is subject to section 307(d) of the Act. Accordingly, the EPA has established a docket (No. A–91–71), which consists of an organized and complete file of all information submitted to, or otherwise considered by, the EPA in the development of this action. The docket includes all memoranda and studies cited by the EPA in this preamble. The principal purposes of the docket are: (1) To allow interested parties a means to identify and locate documents so that they can effectively participate in the rulemaking process, and (2) to serve as the record in case of judicial review. The docket is available for public inspection at EPA's Air Docket, which is listed under the ADDRESSES section of this document.

B. Office of Management and Budget (OMB) Review

1. Paperwork Reduction Act

These revisions contain no changes to the information collection requirements of the current NSPS that would increase the burden to sources, and the currently approved Office of Management and Budget (OMB) information collection requests are still in force for the amended rules. These information collection requests are identified as number 1053.05, OMB 2060–0023, for 40 CFR 60.40a–49a and number 1088.08, OMB 2060–0072 for 40 CFR 60.40b-49b. 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.

Some changes in the rule, such as allowing the submittal of electronic reports, are provided as an option to sources, and should reduce burden to those sources electing to use this report format. Other rule changes, such as the difference in numerical NO_X emission limits and the output-based format of the standard, do not result in additional recordkeeping and reporting requirements, beyond those already required by other programs such as the Acid Rain requirements in part 75.

2. Executive Order 12866

Under Executive Order 12866 (58 FR 51735, Oct. 4, 1994), the Agency must determine whether the regulatory action is ''significant'' and, therefore, subject to OMB review and the requirements of the Executive Order. The Order defines ''significant'' regulatory action as one that is likely to lead to a rule that may: (1) have an annual effect on the economy of $100 million or more, or adversely and materially affect 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 obligation of recipients thereof; (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, the EPA has determined that this rule is a ''significant regulatory action'' because this action may have an annual effect on the economy of $100 million or more and it raises novel policy issues, such as the output-based format of the subpart Da emission limit for new sources and the fuel neutral approach to the emission limits under both subparts. As such, this action was submitted to OMB for review. Changes made in response to OMB suggestions or recommendations will be documented in the public record.

C. Unfunded Mandates Reform Act

Under section 202 of the Unfunded Mandates Reform Act of 1995 (''UMRA''), signed into law on March 22, 1995, the EPA must prepare a statement to accompany any proposed rule where the estimated costs to State, local, or tribal governments, or to the private sector, will be $100 million or more in any one year. Under section 205, the EPA must select the most cost-effective, least costly, or least burdensome alternative that achieves the objective of the rule and is consistent with statutory requirements. Section 203 requires the EPA to establish a plan for informing and advising any small governments that may be significantly impacted by the rule.

The unfunded mandates statement under section 202 must include: (1) A citation of the statutory authority under which the rule is proposed; (2) an assessment of the costs and benefits of the rule, including the effect of the mandate on health, safety and the environment, and the federal resources available to defray the costs; (3) where feasible, estimates of future compliance costs and disproportionate impacts upon particular geographic or social segments of the nation or industry; (4) where relevant, an estimate of the effect on the national economy; and, (5) a description of the EPA's prior consultation with State, local, and tribal officials.

Since this final rule is estimated to impose costs to the private sector in excess of $100 million, the EPA has prepared the following statement with respect to these impacts.

1. Statutory Authority

The statutory authority for this rulemaking is identified and described in section I.A of the preamble. As required by section 205 of the UMRA, and as described more fully in the proposal preamble (62 FR 36948, section III) and section III of this preamble, the EPA has chosen to promulgate a rule that is the least burdensome alternative for regulation of these sources that meets the statutory requirements under the Act.

2. Costs and Benefits

As described in section VI of the proposal preamble, the estimate of annual social cost for the regulation is $40 million for utility boilers and $41 million for industrial boilers in the year 2000. Certain simplifying assumptions, such as no fuel switching in response to the rule, may have resulted in a significant overestimation of these costs.

The pollution control costs will not impose direct costs for State, local, and tribal governments. Indirectly, these entities face increased costs in the form of higher prices for electricity and the goods produced in the facilities requiring new industrial boilers that would be subject to this final rule. There are no federal funds available to assist State, local, or tribal governments with these indirect costs.

Because this regulation affects boilers as they are constructed (or modified), the emission reductions attributable to the regulation increase year by year until all existing boilers have been replaced. In the year 2000, the NO_X emission reduction relative to the baseline for utility boilers is estimated to be 26,000 tons per year. In the year 2000, the NO_X emission reduction relative to the baseline for industrial boilers that represent net additions to existing capacity is estimated to be 20,000 tons per year. Emissions reductions from replacement boilers are not quantified because of difficulties in characterizing emission rates for the boilers being replaced and the inability of the replacement model to predict selection of different types of boilers in both the baseline case and in response to the regulation. A qualitative analysis of industrial boiler replacement raises the possibility that replacement delay due to the revision may keep some boilers continuing to emit at a higher level than they would in the baseline case where they would be replaced by a lower emitting boiler.

Reducing emissions of NO_X has the potential to benefit society in a number of ways. Emissions of NO_X result in a wide range of damages, ranging from human health effects to impacts on ecosystems. They not only contribute to ambient levels of potentially harmful nitrogen compounds, but they also have important precursor effects. In combination with volatile organic compounds (VOCs), they contribute to the formation of ground level ozone. Along with emissions of sulfur oxides, they are also precursors to particulate matter and acidic deposition.

See Table 2 for a summary of linkages between NO_X emissions and damage categories.

TABLE 2.—LINKAGES BETWEEN NO_X EMISSIONS AND DAMAGE CATEGORIES: STRENGTH OF THE EVIDENCE

	Direct effects	Precursor effects		
	Ambient NO_X levels	Ambient ozone levels	Ambient particulate matter	Acid deposition
Human Health:				
Acute Morbidity	√√√	√√√	√√√	√
Chronic Morbidity	√√	√	√√√	
Mortality	....	√	√√√	....
Ecosystems:				
Terrestrial	√√[1]	√√	√√	....
Aquatic	√√	....	....	√√√
Commercial Biological Systems[2]:				
Agriculture	√	√√√	....	....
Forestry	....	√√	....	√
Visibility	√√	....	√√√	....
Materials	√√√	....	√√√	....

√ = weak evidence.
√√ = limited evidence.
√√√ = strong evidence.
[1] Evidence indicates that NO_X can have both positive and negative effects in this category.
[2] Evidence for this category relates specifically to certain commercial crop or tree types rather than to the more general terrestrial damages that are covered in the separate ecosystems category.

Benefits are only qualitatively addressed in the regulatory impacts analysis (RIA) because of difficulties in physically locating the not yet built boilers and translating their emission reductions into changes in ambient concentrations of nitrogen compounds, ozone concentrations, and particulate matter concentrations.

3. Future and Disproportionate Costs

The rule is not expected to have any disproportionate budgetary effects on any particular region of the nation, any State, local, or tribal government, or urban or rural or other type of community. Only very small increases in electricity prices are estimated. See section VIII C.4 of the proposal preamble for more detail.

4. Effects on National Economy

Significant effects on the national economy from this rule are not anticipated. See section VIII.C.4 of the proposal preamble for more detail.

5. Consultation with Government Officials

The UMRA requires that EPA describe the extent of the Agency's prior consultation with affected State, local, and tribal officials, summarize the officials' comments or concerns, and summarize the EPA's response to those comments or concerns. In addition, section 203 of the Act requires that the EPA develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a proposal.

In the development of this rule, the EPA has provided small governments (State, local, and tribal) the opportunity to comment on this regulatory program. A fact sheet which summarized the regulatory program, the control options being considered, preliminary revisions, and the projected impacts was forwarded to seven trade associations representing State, local, and tribal governments. A meeting was held for interested parties to discuss and provide comments on the program. Written comments also were requested. The main comments received dealt with the need to consider the impacts of the revisions on small units and facilities. Commenters also stated that the requirement for an integrated resource plan is unnecessary and burdensome for small operators and may constitute an unfunded mandate. In response to this concern, the EPA removed the requirement for an integrated resource plan from this rulemaking. In response to the concern regarding the cost impacts on small industrial steam generating units, the EPA proposed a higher NO_X emission limit for industrial units than it proposed for utility units. The revised limit for industrial units effectively results in no additional controls for gas and distillate oil-fired industrial units over that required to comply with the current emission limits. As described in sections VIII.D.3 and D.4.c of the proposal preamble, the impacts on small businesses and governments have been analyzed and indicate that small governments are not significantly impacted by this rule and thus no plan is required. Public comments received from government entities were largely limited to technical comments on the proposed revisions. However, the City of Tampa, Florida, did raise a burden-related issue due to concerns regarding the potential overlap in applicability between subpart Db and other NSPS provisions affecting municipal waste combustors. As described in section III.D.3, the EPA has addressed their concerns by reinstating the 10-percent exemption and by specifically exempting MWC units from applicability to subpart Db.

D. Executive Order 12875

Under Executive Order 12875, EPA may not issue a regulation that is not required by statute and that creates a mandate upon a State, local or tribal government, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by those governments. If the mandate is unfunded, EPA must provide to OMB a description of the extent of EPA's prior consultation with representatives of affected State, local and tribal governments, the nature of their concerns, copies of any written communications from the governments, and a statement supporting the need to issue the regulation. In addition, Executive Order 12875 requires EPA to develop an effective process permitting elected officials and other representatives of State, local and tribal governments "to provide meaningful and timely input in the development of regulatory proposals containing significant unfunded mandates."

The EPA has concluded that this rule may create a mandate on State, local, and/or tribal governments and that the Federal government will not provide the funds necessary to pay the direct costs incurred by the State, local and/or tribal governments in complying with the mandate. These governments will also have the responsibility to carry out the rule by incorporating it into permits and enforcing it, as delegated. They will collect permit fees that pay for the costs of applying the rule.

In developing this rule, EPA consulted with these governments to enable them to provide meaningful and timely input in the development of this rule. As discussed in section IV.C.5 of this preamble, EPA provided numerous opportunities for these stakeholders to comment on the proposed amendments and has carefully considered their input.

As described in sections IV.C.2 and IV.C.3, EPA does not expect this rule to impose direct compliance costs on State, local, and tribal governments. At most, these entities will face increased indirect costs in the form of slightly higher prices for electricity and the goods produced in facilities requiring new industrial boilers that would be subject to this final rule. Compared to the estimated health and environmental benefits, described in section IV.C.2 of this preamble, EPA believes the need to issue this final rule outweighs the potential costs to these governmental entities.

E. Executive Order 13084

Under Executive Order 13084, EPA may not issue a regulation that is not required by statute, that significantly or uniquely affects the communities of Indian tribal governments, and that imposes substantial direct compliance costs on those communities, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by the tribal governments. If the mandate is unfunded, EPA must provide to OMB, in a separately identified section of the preamble to the rule, a description of the extent of EPA's prior consultation with representatives of affected tribal governments, a summary of the nature of their concerns, and a statement supporting the need to issue the regulation. In addition, Executive Order 13084 requires EPA to develop an effective process permitting elected and other representatives of Indian tribal governments ''to provide meaningful and timely input in the development of regulatory policies on matters that significantly or uniquely affect their communities.''

Today's rule does not significantly or uniquely affect the communities of Indian tribal governments. The EPA received extensive public comments on the proposed amendments. None of the commenters raised any issues of direct significance to Indian tribal governments. Accordingly, the requirements of section 3(b) of Executive Order 13084 do not apply to this rule.

F. Regulatory Flexibility Act

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule. EPA has also determined that this rule will not have a significant economic impact on a substantial number of small entities. The Regulatory Flexibility Act (RFA) requires EPA to give special consideration to the impact of regulation on small businesses, small organizations, and small governmental units. The major purpose of the RFA is to keep paperwork and regulatory requirements from getting out of proportion to the scale of the entities being regulated, without compromising the objectives of, in this case, the Clean Air Act. The RFA specifies that the EPA must prepare an initial regulatory flexibility analysis if a proposed regulation will have a significant economic impact on a substantial number of small entities.

Firms in the electric services industry (SIC 4911) are classified as small by the U.S. Small Business Administration if the firm produces less than four million megawatts a year. For the time period of the analysis (1996 to 2000), one projected new utility boiler may be affected and small. Of the 13 projected new utility boilers, 10 are known to not be small, and 2 of the remaining 3 are not expected to incur additional control costs due to the regulation. The size of the owning entity is unknown for the remaining utility boiler. That boiler also has the smallest cost in mills/kWh (0.07) of the 11 projected units to have additional control costs. Therefore, no significant small business impacts are anticipated for the utility boilers.

Regarding industrial boilers, EPA expects that some small businesses may face additional pollution control costs. It is difficult to project the number of industrial steam generating units that will both incur control costs under the regulation and be owned by a small entity. Since the rule only affects new sources, and plans for new industrial boilers are not available (as they are for electric utilities), linking new projected boilers to size of owning entity is difficult. The projection of 381 new boilers has 293 of the boilers incurring no costs because they are projected to be either gas-fired or distillate-oil-fired units that would require no additional control. Some of the 88 remaining boilers which are projected to incur costs in complying with the regulation may be owned by small entities. The size of the owning entity and the size of the boiler are not related in any simple way, but smaller entities may be more likely to have a smaller boiler. The applicability size cut off of 100 million Btu/hour heat input for industrial boilers would be expected to result in fewer small entities being affected. Since only 88 industrial boilers are expected to incur any costs and many of them are likely to be owned by large entities, the EPA projects that fewer than 88 of these boilers will be owned by small entities.

The information used for economic impact analysis for the proposed rule matches boiler size and fuel type to various industries. These data overestimate the share of boilers that are residual-oil-fired and coal-fired, but the data are nonetheless useful for estimating the potential economic impact of the rule on small entities in terms of cost-to-sales ratio. This analysis estimates costs as a percent of value of shipments (closely related to sales) for affected facilities. The average control cost as a percentage of value of shipments for all affected facilities is 0.07 percent. The range of average control cost across industries varies from a low of 0.004 percent for primary metals to a high of 0.8 percent for the paper industry. Although the cost varies by industry, boiler size, and fuel, it is unlikely that any affected small entities will have a control cost to sales ratio of greater than one percent.

G. Executive Order 13045

Executive Order 13045 applies to any rule that EPA determines (1) economically significant as defined under Executive Order 12866, and (2) the environmental health or safety risk addressed by the rule has a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This final rule is not subject to Executive Order 13045, entitled Protection of Children from Environmental Health Risks and Safety Risks (62 FR 19885, April 23, 1997), because it does not involve decisions on environmental health risks or safety risks that may disproportionately affect children.

H. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA) directs all Federal agencies to use voluntary consensus standards instead of government-unique standards in their 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 and analytical procedures, business practices, etc.) that are developed or adopted by one or more voluntary consensus standards bodies. Examples of organizations generally regarded as voluntary consensus standards bodies include the American Society for Testing and Materials (ASTM), the National Fire Protection Association (NFPA), and the Society of Automotive Engineers (SAE). The NTTAA requires Federal agencies like EPA to provide Congress, through OMB, with explanations when an agency decides not to 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, consideration of voluntary consensus standards is not relevant to this action.

I. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2).

J. Clean Air Act Procedural Requirements

1. Administrator's Listing—Section 111

As prescribed by section 111(b)(1)(A) of the Act, establishment of standards of performance for electric utility steam generating units and industrial-commercial-institutional steam generating units was preceded by the Administrator's determination that these sources contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

2. Periodic Review—Section 111

This regulation will be reviewed again 8 years from the date of promulgation of these revisions to the standard. The review will include an assessment of the need for integration with other programs, enforceability, improvements in emission control technology, and reporting requirements.

3. External Participation—Section 117

In accordance with section 117 of the Act, publication of this review was preceded by consultation with independent experts. The Administrator has considered comments on several aspects of the proposed revisions, including economic and technical issues.

4. Economic Impact Analysis—Section 317

Section 317 of the Act requires the EPA to prepare an economic impact assessment for any emission standards under section 111 of the Act. An economic impact assessment was prepared for the proposed revision to the standards. In the manner described above under the discussions of the impacts of, and rationale for, the proposed revision to the standards, the EPA considered all aspects of the assessments in promulgating the revision to the standards. The economic impact assessment is included in the docket listed at the beginning of this document under **SUPPLEMENTARY INFORMATION.**

Statutory Authority

The statutory authority for this rule is provided by sections 101, 111, 114, 301, and 407 of the Clean Air Act, as Amended; 42 U.S.C. 7401, 7411, 7414, 7601, and 7651f.

List of Subjects in 40 CFR Part 60

Environmental protection, Air pollution control, Electric utility steam generating units, Industrial-commercial-institutional steam generating units, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: September 3, 1998

Carol M. Browner,

Administrator.

For the reasons set out in the preamble, title 40, chapter 1 of the Code of Federal Regulations is amended as follows.

PART 60—[AMENDED]

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

Authority: 42 U.S.C. 7401, 7411, 7413, 7414, 7416, 7601, and 7602.

Subpart Da—[Amended]

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

§ 60.40a Applicability and designation of affected facility.

* * * * *

(b) Unless and until subpart GG of this part extends the applicability of subpart GG of this part to electric utility steam generators, this subpart applies to electric utility combined cycle gas turbines that are capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel in the steam generator. 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 of this part.)

* * * * *

3. Section 60.41a is amended by adding a definition for ''Gross output'' in alphabetical order to read as follows:

§ 60.41a Definitions.

* * * * *

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus one half the useful thermal output (i.e., steam delivered to an industrial process).

* * * * *

4. Section 60.44a is amended by revising paragraphs (a) introductory text and (c) introductory text and by adding paragraph (d) to read as follows:

§ 60.44a Standard for nitrogen oxides.

(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, except as provided under paragraphs (b) and (d) of this section, any gases which contain nitrogen oxides (expressed as NO_2) in excess of the following emission limits, based on a 30-day rolling average:

* * * * *

(c) Except as provided under paragraph (d) of this section, when two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

* * * * *

(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 any gases which contain nitrogen oxides (expressed as NO_2) in excess of 200 nanograms per joule 1.6 pounds per megawatt-hour) gross energy output, based on a 30-day rolling average.

(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 modification or reconstruction commenced after July 9, 1997 any gases which contain nitrogen oxides (expressed as NO_2) in excess of 65 ng/J_I (0.15 pounds per million Btu) heat input, based on a 30-day rolling average.

5. Section 60.46a is amended by adding paragraph (i) to read as follows:

§ 60.46a Compliance provisions.

* * * * *

(i) *Compliance provisions for sources subject to § 60.44a(d).* (1) The owner or operator of an affected facility subject to § 60.44a(d)(1) (new source constructed after July 7, 1997) 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(1) and divided by the average hourly gross heat rate measured according to the provisions of § 60.47a(k).

(2) The owner or operator of an affected facility subject to § 60.44a(d)(2) (modified or reconstructed source after July 7, 1997) shall demonstrate compliance according to the provisions of paragraph (g) of this section.

6. Section 60.47a is amended by revising paragraph (c) and by adding paragraphs (k) and (l) to read as follows:

§ 60.47a Emission monitoring.

* * * * *

(c)(1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a nitrogen oxides 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.

* * * * *

(k) The procedures specified in paragraphs (k)(1) through (k)(3) of this section shall be used to determine gross heat rate for sources demonstrating compliance with the output-based standard under § 60.44a(d)(1).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in megawatt-hour on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 50 percent of the gross thermal output of the process steam measured in accordance with paragraph (k)(2) of this section.

(l) The owner or operator of an affected facility demonstrating compliance with the output-based standard under § 60.44a(d)(1) shall, install, certify, operate, and maintain a continuous flow monitoring system, and record the output of the system, for measuring the flow of exhaust gases discharged to the atmosphere.

7. Section 60.49a is amended by revising the first sentence of paragraph (i) and adding paragraph (j) to read as follows:

§ 60.49a Reporting requirements.

* * * * *

(i) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility shall submit the written reports required under this section and subpart A of this part to the Administrator for every calendar quarter. * * *

(j) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (b) and (h) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

Subpart Db—[Amended]

8. Section 60.40b is amended by adding paragraphs (h) and (i) to read as follows:

§ 60.40b Applicability and delegation of authority.

* * * * *

(h) Affected facilities which meet the applicability requirements under subpart Eb (Standards of performance for municipal waste combustors; § 60.50b) are not subject to this subpart.

(i) Unless and until subpart GG of this part is revised to extend the applicability of subpart GG of this part to steam generator units subject to this subpart, this subpart will continue to apply to combined cycle gas turbines that are capable of combusting more than 29 MW (100 million Btu/hour) heat input of fossil fuel in the steam generator. 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 of this part.)

9. Section 60.44b is amended by revising paragraphs (a) introductory text, (b) introductory text, (c), and (e) introductory text and by adding paragraph (l) to read as follows:

§ 60.44b Standard for nitrogen oxides.

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO_2) in excess of the following emission limits:

* * * * *

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides in excess of a limit determined by the use of the following formula:

* * * * *

(c) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain nitrogen oxides in excess of the emission limit for the coal or oil, or mixtures of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

* * * * *

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain nitrogen oxides in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

* * * * *

(l) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility which commenced construction, modification, or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO_2) in excess of the following limits:

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

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = [(0.10 * H_{go})+(0.20 * H_r)]/(H_{go}+H_r)$$

Where:

E_n is the NO_X emission limit, (lb/million Btu),

H_{go} is the heat input from combustion of natural gas or distillate oil, and

H_r is the heat input from combustion of any other fuel.

10. Section 60.48b is amended by revising paragraph (b) 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 shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a nitrogen oxides 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 § 60.49b. Data reported to meet the requirements of § 60.49b 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.

* * * * *

11. Section 60.49b is amended by adding paragraph (v) to read as follows:

§ 60.49b Reporting and recordkeeping requirements.

* * * * *

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

[FR Doc. 98–24733 Filed 9–15–98; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[FRL—6157–1]

RIN 2060–AH74

National Emission Standards for Hazardous Air Pollutants for Source Category: Pulp and Paper Production

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; interpretation and technical amendment.

SUMMARY: Under the authority of the Clean Air Act, the EPA has promulgated standards at 40 CFR part 63, subpart S (63 FR 18504, April 15, 1998) to reduce hazardous air pollutant (HAP) emissions from the pulp and paper production source category. This rule is known as