ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL-5854-5]

RIN-2060-AE56

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed revisions.

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. This document presents EPA's findings and proposes revisions to the existing NO_x standards.

The proposed changes to the existing standards for NO_x emissions reduce the numerical NO_x emission limits for both utility and industrial steam generating units to reflect the performance of best demonstrated technology. The proposal also changes the format of the revised NO_x emission limit for electric utility steam generating units to an output-based format to promote energy efficiency and pollution prevention.

As a separate activity, EPA has also reviewed the quarterly sulfur dioxide, NO_X, and opacity emission reporting requirements of the utility and industrial steam generating unit regulations contained in 40 CFR part 60, subpart Da and Db. This document proposes to 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: Comments. Comments on the proposed revisions must be received on or before (insert date 60 days from publication date in the Federal Register) at the address noted below.

Public Hearing. A public hearing will be held, if requested, to provide interested persons an opportunity for oral presentations of data, views, or arguments concerning the proposed revisions. If anyone contacts the EPA requesting to speak at a public hearing by (3 weeks after proposal), a public hearing will be held on (about 30 days after proposal) beginning at 9:00 a.m. The public hearing is only for the oral presentations of comments with the EPA asking clarifying questions. Persons interested in attending the hearing should call Ms. Donna Collins at (919) 541-5578 to verify that a hearing will occur.

Request to Speak at Hearing. Persons wishing to present oral testimony must contact EPA by (3 weeks after proposal).

ADDRESSES: Interested parties may submit written comments (in duplicate if possible) to 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, S.W., Washington, D.C. 20460. The Agency requests that a separate copy also be sent to the contact person listed below. 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.

Comments and data also may be submitted electronically by sending electronic mail (e-mail) to: a-and-r-docket@epamail.epa.gov. Electronic comments must be submitted as an ASCII file avoiding the use of special characters and any form of encryption. Comments and data also will be accepted on disks in WordPerfect in 5.1 file format or ASCII file format. All comments and data in electronic form must be identified by the docket number A-92-71. No Confidential Business Information (CBI) should be submitted through e-mail. Electronic comments on this proposed rule may be filed online at many Federal Depository Libraries.

Public Hearing. If a public hearing is held, it will be held at EPA’s Office of Administration Auditorium, Research Triangle Park, North Carolina. Persons wishing to present oral testimony should notify Ms. Donna Collins, Combustion Group (MD-13), U.S. Environmental Protection

Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5578, FAX number (919) 541-5450.

Technical Support Documents. The technical support documents summarizing information gathered during the review 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 or "New Source Performance Standards, Subpart Db - Technical Support for Proposed Revisions to NO_X Standard", EPA-453/R-95-012.

Docket. Docket No. A-92-71, containing supporting information used in developing the proposed revisions, is available for public inspection and copying from 8:30 a.m. to 12:00 p.m. and 1:00 to 3:00 p.m., Monday through Friday, at EPA's Air Docket Section, Waterside Mall, Room 1500, 1st Floor, 401 M Street, S.W., Washington, D.C. 20460. A reasonable fee may be changed for copying docket materials, including printed paper versions of electronic comments which do not include any information claimed as CBI.

FOR FURTHER INFORMATION CONTACT: For information concerning specific aspects of this proposal, 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.

SUPPLEMENTARY INFORMATION: The following outline is provided to aid in locating information in this notice.

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This notice is also available on the Technology Transfer Network (TTN), one of the EPA's electronic bulletin boards. The TTN provides information and technology exchange in various areas of air pollution control. The service is free, except for the cost of a phone call. Dial (919) 541-5742 for up to a 14,400 bps modem. The TTN is also accessible via the Internet at "ttnwww.rtpnc.epa.gov." If more information on the TTN is needed, call the HELP line at (919) 541-5384.

I. Background

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 sulfur dioxide (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).

The current NO_x standards for new utility steam generating units were promulgated on June 11, 1979 (44 FR 33580). The NSPS apply to electric utility steam generating units capable of firing more than 73 megawatts (MW)(250 million Btu/hour) heat input of fossil fuel, for which construction or modification commenced after September 18, 1978. The current NSPS also apply to industrial cogeneration facilities that sell more than 25 MW of electrical output and more than one-third of their potential output capacity to any utility power distribution system. The current NO_x standards for new electric utility steam generating units are fuel-specific and were based on combustion modification techniques. At the time the NSPS was promulgated, the most effective combustion modification techniques for reducing NO_x emissions from utility steam generating units were judged to be combinations of staged combustion [overfire air (OFA)], low excess air (LEA), and reduced heat release rate.

The NSPS for NO_x emissions for industrial steam generating units was promulgated on November 25, 1986 (51 FR 42768). The NSPS apply to industrial steam generating units with a heat input capacity greater than 29 MW (100 million Btu/hour), for which construction, modification, or reconstruction commenced after June 19, 1984. The NO_x standards promulgated for industrial steam generating units are fuel- and boiler-specific and were based on the performance of LEA and LEA-staged combustion modification techniques.

II. Proposed Revisions

Standards of performance for new sources established under section 111 of the Act are to reflect the application of the best system of emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. This level of control is commonly referred to as best demonstrated technology (BDT).

The proposed standards would 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 (insert date of publication in Federal Register) would be affected by the proposed revisions.

The NO_x emission limit proposed in today's notice for subpart Da units is 170 nanograms per joule (ng/J) [1.35 lb/megawatt-hour (MWh)] net energy output regardless of fuel type. For subpart Db units, the NO_X emission limit being proposed is 87 ng/J (0.20 lb/million Btu) heat input from the combustion of any gaseous fuel, liquid fuel, or solid fuel; however, for low heat release rate units firing natural gas or distillate oil, the current NO_X emission limit of 43 ng/J (0.10 lb/million Btu) 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 as the one currently in subparts Da and Db.

The proposed revisions to the quarterly SO_2, NO_X, and opacity reporting requirements of subparts Da and Db would allow electronic quarterly reports to be submitted in lieu of the written reports currently required under sections 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 consistent with the electronic data reporting (EDR) format specified by the Administrator under section 75.64(d) for use in the Title IV Acid Rain Program. 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.

III. Rationale for Proposed Revisions

A. Performance of NO_x Control Technology

The control technologies that are commercially available for reducing NO_x emissions can be grouped into one of two fundamentally different techniques: combustion control and flue gas treatment. Generally, combustion controls reduce NO_x emissions by suppressing NO_x formation during the combustion process. Flue gas treatment controls are add-on controls that reduce NO_x emissions after combustion has occurred.

Combustion control techniques generally employed on wall-fired pulverized coal (PC) fired units include low NO_x burners (LNB) (i.e., burners that incorporate LEA and air staging within the burner) or LNB with OFA. For tangentially-fired PC units, combustion control techniques generally employed include LNB (i.e., a low NO_x configured coal and air nozzle array and injection of a portion of the combustion air through air nozzles above, but essentially within the same waterwall hole as the coal and air nozzle array) or LNB with separated OFA (i.e., LNB with additional air nozzles above but outside the waterwall hole that includes the coal and air nozzle array). For control of fluidized bed combustion (FBC) and stoker steam generating units, air staging is the form of combustion control employed.

Another group of combustion control techniques are based on the use of clean fuels (i.e., natural gas). Commercially available gas-based control techniques are reburning and cofiring with coal or oil. In reburning, natural gas is injected above the primary combustion zone to create a fuel-rich zone to reduce burner-generated NO_X to molecular nitrogen (N_2) and water vapor. It is necessary to add overfire air above the reburning zone to complete combustion of the reburning fuel. Natural gas cofiring consists of injecting and combusting natural gas near or concurrently with the main oil or coal fuel.

Two commercially available flue gas treatment technologies for reducing NO_X emissions from fossil fuel-fired steam generating units are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). In SNCR, ammonia (NH_3) or urea is injected into the flue gas to reduce NO_X to N_2 and water. The SCR utilizes injection of NH_3 into the flue gas in the presence of a catalyst. The catalyst promotes reactions that convert NO_X to N_2 and water at higher removal efficiencies and lower flue gas temperatures than required for SNCR.

Application of flue gas treatment technologies on coal-fired boilers in the United States (U.S.) has grown considerably during the past two years. However, both SNCR and SCR technologies have been applied widely to commercial-scale gas- and oil-fired steam generating units. Both technologies have been applied to coal-fired steam generating units outside the U.S. The SCR technology has been implemented on coal-fired steam generating units in Germany and Japan over the past 15 years and has achieved substantially reduced NO_X emission levels. A recent EPA report notes that there are 72 coal-fired plants (137 units) in Germany, 28 coal-fired plants (40 units) in Japan, 9 coal-fired plants (29 units) in Italy, and 8 coal-fired plants (10 units) in other European countries using SCR (See EPA report, "Performance of SCR Technology for NO_X Emissions at Coal-Fired Electric Utility Units in the United States and Western Europe").

The SCR technology is currently being applied on seven coal-fired steam generating units in the U.S. These applications are described in Table 1.

TABLE 1. FULL-SCALE SCR EXPERIENCE ON COAL-FIRED UNITS IN THE U.S.

Plant and Unit No.	State	Size (MWe)	Year Online
Birchwood 1	VA	245	1996
Carney's Point 1	NJ	140	1994
Carney's Point 2	NJ	140	1994
Indiantown	FL	370	1996
Logan 1	NJ	230	1994

Merrimack 2	NH	320	1995
Stanton 2	FL	460	1996

The SNCR technology has been applied in the U.S. to a number of coal-fired utility and industrial steam generating units. Each of these control technologies is discussed in the technical support documents.

The performance of combustion controls applied to subpart Da coal-fired steam generating units was evaluated through statistical analyses of continuous emission monitoring (CEM) data obtained from operators of conventional and FBC electric utility steam generating units. The objective of the analyses was to assess long-term NO_x emission levels that can be achieved continuously using combustion controls. For the data analyses, individual steam generating units were selected to represent the primary coal types and furnace configurations (PC and FBC) used in this source category. The procedures used to select individual steam generating units for statistical analyses, the statistical analyses that were performed, and the results of the statistical analyses for six sets of data reflecting recent operating experience for subpart Da units using combustion controls are described in the technical support document for the subpart Da revision. The results indicate that the achievable NO_x emissions from each steam generating unit are lower than the current standard.[1]

The performance of combustion controls applied to stoker coal-fired steam generating units was not evaluated using a detailed statistical analyses of CEM data. However, long-term NO_x emission data obtained from four subpart Da stoker units with combustion controls (i.e., air staging) were typically between 0.48 and 0.53 lb/million Btu heat input. In stoker steam generating units, a minimum amount of undergrate air must be used to provide adequate mixing and cooling. Since the use of air staging reduces undergrate air flow, there may be a limit to the degree of air staging used in stoker units and consequently to the NO_x reduction that can be achieved.

A statistical analysis of combustion controls applied to gas- and oil-fired utility steam generating units was also not performed since: (1) there are no known operating subpart Da natural gas- or oil-fired utility units; (2) there are pre-NSPS utility steam generating units burning these fuels that have been retrofit with combustion controls, but long-term CEM data for these units were

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It should be noted that CEM data submitted to EPA under 40 CFR part 75 were not available during the development of the technical support document. However, a preliminary examination of these data shows that the average 30-day rolling NO_x emission rates were as low as 0.22 lb/million Btu heat input from conventional PC units applying only LNB.

unavailable during the development of the technical support document.

The NO_x control performances of both flue gas treatment technologies (i.e., SNCR and SCR) were evaluated based on short-term test data from retrofit installations and permitted conditions for new units. Long-term CEM data were used to evaluate SNCR for FBC boilers and SCR for pulverized coal-fired units. The flue gas treatment NO_x control technology currently receiving the most attention in the U.S. is SCR for conventional coal-fired utility steam generating units.

Short-term test results of SNCR applied to fossil-fuel fired utility boilers were obtained on 2 conventional coal-fired, 7 FBC, 2 oil-fired, and 10 gas-fired applications. For the conventional coal-fired units, the NO_x reductions varied from 30 to 60 percent at full load, with NO_x emission levels from 0.5 to 0.76 lb/million Btu. These units were originally uncontrolled pre-NSPS units. The NO_x emissions from the seven FBC units ranged from 0.03 to 0.1 lb/million Btu at full load conditions. For oil-fired units, the NO_x emissions varied from 0.14 to 0.17 lb/million Btu, depending on the NH_3/NO_x ratio. This corresponds to NO_x removal efficiencies of 48 to 56 percent from uncontrolled levels. For gas-fired boilers, NO_x emissions ranged from 0.07 to 0.10 lb/million Btu at full load conditions or about 10 to

40 percent reduction in NO_x emissions. One utility company reported information on the retrofit of 16 gas/oil-fired steam generating units indicating a 25 to 30 percent reduction in NO_x emissions from combustion-controlled levels.

For evaluating the performance of SCR, short-term test results were obtained from pilot-scale installations at two coal-fired and one oil-fired steam generating unit, and from commercial-scale installations at two coal-fired and two gas-fired steam generating units. Permitted conditions for six new coal-fired facilities and two new gas-fired facilities equipped with SCR systems also were obtained. In addition, long-term CEM NO_x emission data for full-scale SCR applications at five pulverized coal-fired units with SCR were obtained. To date, EPA is not aware of any full-scale SCR applications on oil-firing steam generating units in the U.S.

For the pilot-scale coal-fired demonstrations, the project results indicate that 75 to 80 percent NO_x reductions from uncontrolled levels were achieved.

Commercial-scale SCR installations on coal-fired units currently operating in the U.S. are designed for NO_x reductions between 50 and 63 percent from combustion control levels, with design and permitted NH_3 slip levels (i.e., amount of unreacted NH_3 in exhaust gas) of 5 ppm or less.

Short-term test results obtained from new installations range from 0.10 to 0.15 lb/million Btu. The long-term CEM data obtained from two of these coal-fired units have been evaluated using statistical analyses. The results indicate that the estimated achievable NO_x emission rate from both units is 0.142 lb/million Btu heat input, on a 30-day rolling average basis. Further, the EPA recently analyzed long-term CEM data from five new U.S. coal-fired units. All units operated below their permitted NOx emission levels, which were no greater than 0.17 lb/million Btu (EPA report "Performance of Selective Catalytic Reduction Technology for NOx Emissions at Coal-Fired Electric Utility Units in the United States and Western Europe"). Currently, EPA does not have CEM data available for a coal-fired U.S. unit that just started up (Birchwood Unit 1). However, in a recent public forum (cite: presentation by David Gallaspy, VP Asia Pacific Rim, Southern Electric International, at the 5th Annual CCT Conference, Tampa, Florida, Jan. 7-10, 1997) the operating utility stated that this unit is achieving 0.15 to 0.16 lb/million Btu with combustion controls alone and 0.07 to 0.08 lb/million Btu with the addition of SCR.

Permitted NO_x emission levels (30-day rolling average) for new coal-fired utility steam generating units equipped with SCR typically range from 0.15 lb/million Btu for pulverized coal-fired units to 0.25 lb/million Btu for stoker units.

For gas-fired steam generating units equipped with SCR, no permitted NO_x emission levels were available for gas-fired utility steam generating units equipped with SCR; however, permitted NO_x levels range from 0.01 to 0.03 lb/million Btu for new gas-fired industrial steam generating units equipped with SCR. No permitted NO_x levels were available for new oil-fired steam generating units, either utility or industrial, equipped with SCR.

B. Control Technology Costs

The annualized costs and cost effectiveness of the NO_x control options for utility steam generating units are given in Table 2. The cost algorithms and assumptions used to estimate capital and annualized costs and the model boilers developed for analyses are described in the technical support documents.[2] (For SCR and SNCR costs, refer to the Draft Technical Report "Cost Estimates for Selected Applications of NO_x Control Technologies on Stationary Combustion Boilers," March 1996.)

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[2] Note that updated costs of SNCR and SCR applications have been presented in the document "Cost Estimates for Selected Applications of NO_x Control Technologies on Stationary Combustion Boilers," March 1996. These updated costs are shown in Table 2.

TABLE 2. ANNUALIZED COSTS AND INCREMENTAL COST EFFECTIVENESS (OVER THE BASELINE) OF NO_X CONTROLS ON UTILITY STEAM GENERATING UNITS (1995 Dollars)[3]

Steam Generating Unit Type	SNCR		SCR	
	Total Annualized Costs (mills/kwh)	Cost Effectiveness ($/ton NO_x Removed)	Total Annualized Costs (mills/kwh)	Cost Effectiveness ($/ton NO_x Removed)
Gas	0.5 - 0.8	1,600 - 3,100	0.55 - 1.1	1,400 - 2,700
Oil	0.7 - 1.0	1,150 - 1,600	0.95 - 1.7	1,550 - 2,700
Coal	1.2 - 1.7	1,170 - 1,630	2.1 - 3.3	1,460 - 2,270

The costs are presented in ranges to reflect the range of sizes (100 to 1,000 MW) of the modeled units. The costs presented are based on a capacity factor of 0.65. The costs for SNCR and SCR with combustion controls are for retrofit installations and these costs for new boilers might be lower than the costs shown in Table 2. (It is not expected that gas- and oil-fired units would utilize SCR to meet the proposed revised standards and, thus, these units would not incur the costs associated with SCR use.) The cost effectiveness listed for each control option represents the incremental cost-effectiveness of applying that technology over the baseline (i.e., NO_x levels being achieved with technologies installed to meet the current NSPS).

[3] In Table 2, the SNCR and SCR costs are for applications on wall-fired boilers, designed to achieve a NO_x emission limit of 0.15 lb/million Btu. The baseline NO_x levels used in determining the cost-effectiveness estimates were: (1) 0.45 lb/million Btu for coal-fired boilers, (2) 0.25 lb/million Btu for gas-fired boilers, and (3) 0.30 lb/million Btu for oil-fired boilers.

The main differences between industrial steam generating units and utility steam generating units are that industrial steam generating units tend to be smaller and tend to operate at lower capacity factors. The differences between industrial and utility steam generating units would be reflected in the cost impacts of the various NO_x control technologies. Smaller sized and lower capacity factor units tend to have higher cost on a per unit output basis. The annualized costs and cost effectiveness of the NO_x control options, based on a model boiler analysis, for industrial steam generating units are given in Table 3.

The costs are presented in ranges to reflect the range of sizes (100 to 1,000 million Btu per hour) and capacity factors (0.1 to 0.6) of the modeled units. The cost effectiveness listed for each control option represents the

TABLE 3. ANNUALIZED COSTS AND INCREMENTAL COST EFFECTIVENESS (OVER THE BASELINE) OF NO_X CONTROLS ON INDUSTRIAL STEAM GENERATING UNITS (1995 Dollars)

Fuel Type	SNCR		SCR	
	Annualized Costs (expressed as % of steam costs)	Cost Effectiveness (\$/ton NO_x Removed)	Annualized Costs (expressed as % of steam costs)	Cost Effectiveness (\$/ton NO_x Removed)
Gas/Distillate Oil	1.5 - 47.3	3,400 - 95,300	5.4 - 108.5	6,200 - 147,900
Residual Oil	2.2 - 47.5	1,080 - 23,700	6.6 - 113.0	2,500 - 43,100
Coal	1.9 - 15.2	550 - 4,710	10.3 - 45.2	1,590 - 8,700

incremental cost-effectiveness of applying that technology over the baseline (i.e., NO_x levels being achieved with technologies installed to meet the current NSPS).

C. Regulatory Approach

In selecting a regulatory approach for formulating revised standards to limit NO_x emissions from new fossil fuel fired steam generating units, the performance and cost of the NO_x control technologies discussed above were considered. The technical basis selected for establishing revised NO_x emission limits is the performance of SCR (in combination with combustion controls). The regulatory approach adopted to revise the current fuel/boiler-specific standards would establish for both utility and industrial steam generating units one emission standard which would be based on the performance of SCR on coal-fired units in combination with combustion controls. This uniform standard would be applicable regardless of fossil fuel type or boiler type.

This regulatory approach differs from the historical approach to establishing NO_x emission limits for fossil fuel-fired steam generating units, in which different emission limits are developed for different combinations of fuel (gas, oil, coal) and boiler types, based on the performance of a particular control technology applied to each fuel/boiler type combination. The current subparts Da and Db standards for NO_x emissions are based on this approach. Under this new regulatory approach, the focus is on controlling NO_x emissions from the generation of electricity or steam based on BDT without regard to specific type of steam generating equipment. This approach provides an incentive to consider both fuel/boiler type combination and control technology when developing a NO_x control strategy. Since the basis selected for the revisions is the high NO_x removal performance of SCR, the relationship between boiler NO_x emissions and boiler design, fuel, and operation is of lesser concern than if the basis was the performance of combustion controls. Under the Clean Air Act Amendments of 1990, the definition of “Best Available Control Technology” was revised to include clean fuels. The definition of “continuous system of emission reduction” under section 111 also allows EPA to consider clean fuels because the term includes any process for production or operation of any source which is inherently low polluting or non-polluting. Under this regulatory approach, an emission limit is developed based on the performance of the cleanest fuel so long as there is a technology which allows other fuels to comply with that limit while providing cost-effective NO_x reductions. This approach addresses the primary regulatory concern, NO_x, but also can result in lower carbon dioxide (CO_2), air toxics, particulate, and SO_2 emissions, as well as lower solid waste and waste water discharges.

The EPA’s analysis shows that SCR can reduce NO_x emissions from coal-fired units to 0.15 lb/million Btu heat input. For oil-fired units, SNCR in combination with combustion controls would be able to achieve this NO_x level. New gas-fired units may require some degree of SNCR if improved combustion controls alone are unable to achieve this level.

In light of the cost considerations associated with the application of flue gas treatment over the range of industrial gas-fired and distillate oil-fired units, a higher uniform NO_x emission limit of 0.20 lb/million Btu heat input was selected for industrial steam generating units. Under EPA’s regulatory approach, new gas-fired and distillate oil-fired units would not require any additional controls over those required under the current NSPS. Based on EPA’s cost impact analysis, it is estimated that by establishing the NO_x level at 0.20 lb/million Btu rather than at 0.15 lb/million Btu, the annual nationwide control costs for new industrial steam generating units will be reduced substantially, about 70 percent, since the revision would result in no additional controls on gas- and distillate oil-fired units. Since these gas and distillate oil-fired units tend to be smaller in size and operated at lower capacity factors than coal-fired industrial units, they tend to have much higher cost-effectiveness values associated with the application of flue gas treatment than do coal-fired units.

The single emission limitation approach would 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. 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.

Summary of Analyses. In order to determine the appropriate form and level of control for the proposed revisions, EPA performed extensive analyses of the potential national impacts associated with the revised standards. These analyses examined the potential incremental national environmental and cost impacts resulting from EPA’s regulatory approach in the fifth year following proposal of the revised standards. The environmental impacts of the revised standards were examined by projecting NO_x emissions for each planned utility boiler and industrial boiler. The cost impact analysis of the regulatory approach included an estimation of the unit capital expenditures for air pollution control equipment, as well as operating and maintenance expenses associated with the equipment. These costs were examined both in terms of annualized costs and percent of boiler output. The regulatory approach also was examined in terms of cost per ton of NO_x removed.

The regulatory baseline used for the national impact analyses consists of permitted levels for the planned utility steam generating units and the existing NSPS applicable to industrial steam generating units (i.e., subpart Db). The projected 5-year utility boiler population was based on information obtained from two published reports which list planned utility units. Utility owners and regulatory agencies were contacted to update these projections and to determine the permitted NO_x emission levels for these units. It is estimated that a total of 17 new boilers will be built over the 5-year period, which would become subject to the revised subpart Da NO_x standard. For the industrial boiler category, sales data and projected growth rates were used to estimate the number, capacity, fuel type, and capacity factor of the industrial units expected to be built during a 5-year period. The analysis projects that 381 new industrial steam generating units will be constructed over the 5-year period under the regulatory baseline. This projected total would consist of 293 natural gas- or distillate oil-fired units, 66 residual oil-fired units, and 22 coal-fired units.

Shown in Table 4 are the annualized costs, NO_x reduction (tons/year), and cost effectiveness ($/ton of NO_x removed) for the utility and industrial steam generating units regulated under EPA's regulatory approach. Note that the cost effectiveness is the average incremental costs per ton of NO_x removed over the baseline (i.e., current NSPS). The cost effectiveness is determined by dividing the change in annualized cost by the change in annual emissions, as compared to the current standards.

TABLE 4. SUMMARY OF NATIONAL IMPACTS FOR UTILITY AND INDUSTRIAL STEAM GENERATING UNITS

Impacts	Units	Utility Steam Generating Units	Industrial Steam Generating Units
Annualized Costs: Total	$million/year	40	41
Range	% of boiler output	0 - 4.3	0 - 11.8
Average	% of boiler output	2.0	1.8
NO_X Reduction	Tons/year	25,840	19,980
Cost Effectiveness			
Range	$/Ton NO_X Removed	0 - 3,240	0 - 4,800
Average	$/Ton NO_X Removed	1,510	2,030

As shown in Table 4, under EPA's regulatory approach, national NO_x emissions would be reduced by about 41,560 megagrams (Mg) (45,800 tons) per year. These NO_x reductions on utility and industrial units will be obtained at an average cost effectiveness of about $1,770/ton of NO_x removed.

D. Revised Standard for Electric Utility Steam Generating Units (Subpart Da)

All known operating utility steam generating units currently subject to subpart Da are coal-fired and use some form of combustion control to comply with applicable emission limits. However, six recently installed conventional PC units and some FBC units use add-on NO_x controls. Most new electric utility steam generating units are projected to burn coal. Consequently, the NO_x studies used to develop the proposed revision have concentrated on the combustion of coal.

The current NO_x standards for subpart Da were based on combustion control techniques and are fuel-specific. When these limits were promulgated in 1979, the most effective combustion control techniques for reducing NO_x emissions from utility steam generating units were judged to be combinations of staged combustion, LEA, and reduced heat release rate.

Currently, SCR is considered to be the most effective NO_x control technology for new electric utility steam generating units. Based on available performance data and cost analyses, the Administrator has concluded that the application of SCR represents the best demonstrated system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact, and energy requirements). Consequently, SCR was chosen as the basis for revising the NO_x emission limits due to its relatively high NO_x removal efficiency.

The national average cost effectiveness of additional NO_x control under this regulatory approach is about $1,500/ton NO_x removed. Further, under EPA's regulatory approach, the cost of the installation and operation of the additional NO_x control equipment does not result in any significant adverse economic impacts.

A benefit associated with the use of EPA's regulatory approach as the basis for the revised NO_x standard is that the approach expands 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) can be a method of achieving cost effective emission reductions from these coal-fired steam generating units.

Based on available performance data and cost analyses, the Administrator is proposing today a revised NO_x emission limit for electric utility steam generating units that applies regardless of fuel type and which is based on coal-firing and the performance of SCR control technology in combination with combustion controls. The analysis shows that SCR can reduce NO_x emissions from coal-fired units to 0.15 lb/million Btu heat input or less. This NO_x emission level reflects about a 75 percent reduction in NO_x emissions over the current subpart Da limits for coal-fired units. This NO_x emission level also reflects about a 50 and 25 percent reduction in NO_x emissions over the current subpart Da limits for oil-fired and gas-fired units, respectively.

Regarding the revised NO_x emission limitation, the Administrator sought to achieve the best balance between control technology and environmental, economic, and energy considerations. In selecting a single emission limitation for electric utility steam generating units that would be applicable regardless of fuel type, the Administrator sought not to limit the control options available for compliance, but to provide flexibility for cheaper and less energy intensive control technologies (i.e., by allowing the use of clean fuels for reducing NO_x emissions). Available gas-based control techniques are cofiring with coal or oil, reburning, and switching to gas as the principal fuel. The clean fuel approach fits well with 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 would be viewed as a sound alternative to flue gas treatment technologies for coal or oil burning.

The fuel cost differential between gas and coal is one of the main concerns with the application of gas-based technologies for the reduction of NO_x from coal-fired boilers. Access to gas supply (proximity to pipeline) and long-term gas availability are additional concerns that may limit natural gas use solely for NO_x control. Therefore, selection of SCR in combination with combustion controls as the basis for the proposed revised NO_x limitation is appropriate since this technology is expected to be an important part of the compliance mix for coal-fired boilers. Again, for new oil-fired units, SNCR in combination with combustion controls would be able to achieve the proposed limit. New gas-fired units may require some degree of SNCR if improved combustion controls alone are unable to achieve the revised limitation which reflects a 25 percent reduction in NO_x emissions over the current NO_x standard for gas-fired utility units.

Output-Based Format. The EPA has established pollution prevention as one of the its highest priorities. One of the opportunities for pollution prevention lies in simply using energy efficient technologies to minimize the generation of emissions. The EPA investigated ways to promote energy efficiency in utility plants by changing the manner in which it regulates flue gas NO_x emissions (see EPA white paper, "Use of Output-based Emission Limits in NOx Regulations"). Therefore, in an effort to promote energy efficiency in utility steam generating facilities, the Administrator is proposing an output-based standard, which is a revised format, for subpart Da.

Traditionally, utility NO_x emissions have been controlled on the basis of boiler input energy (lb of NO_x/million Btu heat input). However, input-based limitations allow units with low operating efficiency to emit more NO_x per megawatt (MWe) of electricity produced than more efficient units. Considering two units of equal capacity, under current regulations, the less efficient unit will emit more NO_x because it uses more fuel to produce the same amount of electricity. One way to regulate mass emissions of NO_x and plant efficiency is to express the NO_x emission standard in terms of output energy. Thus, an output-based emission standard would provide a regulatory incentive to enhance unit operating efficiency and reduce NO_x emissions. Two of the possible output-based formats considered for the revised NO_x standard were: (1) mass of NO_x emitted per gross boiler steam output (lb NO_x/million Btu heat output), and (2) mass of NO_x emitted per net energy output [lb NO_x/megawatt-hour(MWh)]. The criteria used for selecting the format were ease in monitoring and compliance testing and ability to promote energy efficiency.

The objective of an output-based standard is to establish a NO_x emission limit in a format that incorporates the effects of plant efficiency. Additionally, the limit should be in a format that is practical to implement. Thus, the format selected must satisfy the following: (1) provide flexibility in promotion of plant efficiency; (2) permit measurement of parameters related to stack NO_x emissions and plant efficiency, on a continuous basis; and (3) be suitable for equitable application on a variety of power plant configurations.

The option of lb NO_x/million Btu steam output accounts only for boiler efficiency and ignores both the turbine cycle efficiency and the effects of energy consumption internal to the plant. The boiler efficiency is mainly dependent on fuel characteristics. Beyond the selection of fuels, plant owners have little control over boiler efficiency. This option, therefore, does not meet the first criterion, because it provides the owners with minimal opportunities for promoting energy efficiency at their respective plants.

The second output-based format option of lb NO_x/MWh net meets all three criteria. In this case, the net plant energy output represents the energy exported out of the plant to other sources. This energy output takes into account all internal energy consumption and losses for the plant. An emission limit based on this format, therefore, provides the owners with all possible opportunities for promoting energy efficiency at their respective plants. This option would require continuous measurement of the mass rate of NO_x emissions and net plant energy output. The net energy output can include both electrical and thermal (process steam) outputs. Both of these energy outputs are relatively easy to measure accurately, and currently are measured routinely in power plants. Further, since this option does take into account the auxiliary power requirements, an emission limit based on this format can be applied equitably on a variety of power plant configurations.

Based on this analysis, an emission limit format based on mass of NO_x emissions per net plant energy output is selected for the proposed output-based standard. Because electrical output, measured directly in MW, is the main energy output at all power plants, it is desirable to use a format in “lb NO_x/MWh net.” The EPA, however, requests comments on the selected format of “lb NO_x/MWh net” since a format of “lb NO_x/MWh gross” may be more equitable in light of the varying auxiliary power requirements that may exist at power plants. At cogeneration plants, energy output is associated with electricity and process steam; however, the useful heat (Btu/hr) present in steam can be converted to MW.

Compliance with the output-based emission limit would require continuous measurement of plant operating parameters associated with the mass rate of NO_x emissions and net energy outputs. In the case of cogeneration plants where process steam is an output product, means would have to be provided to measure the process steam flow conditions and to determine the useful heat energy portion of the process steam that is interchangeable with electrical output.

Instrumentation already exists in power plants to conduct these measurements since the instrumentation is required to support current emission regulations and normal plant operation. Consequently, compliance with the output-based emission limit is not expected to require any additional instrumentation. A current federal regulation (40 CFR Part 75) requires measurements of both NO_x concentration and flue gas flow rate (for calculating mass rate of NO_x emissions), whereas metering of net electrical output must be provided to account for net electrical sendout from the plant. Therefore, no additional instrumentation is required for conventional utility applications to comply with the output-based emission limit.

However, additional signal input wiring and programming is expected to be required to convert the above measurements into the compliance format (lb NO_x/MWh net).

For cogeneration units, steam is also generated for process use. The energy content of this process steam also must be considered in determining compliance with the output-based standard. This can be accomplished by measuring the total heat content of each process steam source (from the measured flow, pressure, and temperature) and then calculating the useful energy output. If the equivalent electrical energy (useful heat) content of the process steam is expressed in the form of curves, no new instrumentation is required. The information from these curves can be programmed into the plant monitoring system and the equivalent electrical energy for each process steam source can be calculated. This equivalent electrical energy (MW) can be added to the plant’s actual net electrical output (MW) to arrive at the plant’s total net energy output (MW). This total net energy output (MW) used with the mass rate of NO_x emissions (lb/h), yields the NO_x emissions (lb/MWh net) for compliance.

Since all the reported data obtained throughout the development of the revised standards are in the current format of lb/million Btu heat <u>input</u>, EPA applied an efficiency factor to the current format to develop the output-based NO_x limit. The efficiency factor approach was selected because the alternative of converting all the reported data in the database to an output-basis would require extensive data gathering and analyses. Applying a baseline net efficiency would essentially convert the selected heat input-based NO_x level to an output-based emission limit. The EPA solicits comment on this format approach.

The output-based standard must be referenced to a baseline efficiency. Most existing electric utility steam generating plants fall in the range of 24 to 38 percent efficiency. However, newer units (both coal- and gas-fired) operate around 38 percent efficiency; therefore, 38 percent was selected as the baseline efficiency. The EPA requests comment on: (1) whether 38 percent is an appropriate baseline efficiency, (2) how often the baseline efficiency should be reviewed and revised in order to account for future improvements in electric generation technology, and (3) whether a 30-day rolling average is sufficient to account for any operating efficiency variability.

The efficiency of electric utility steam generating units usually is expressed in terms of heat rate, which is the ratio of heat input, based on higher heating value (HHV) of the fuel, to the energy (i.e., electrical) output. The heat rate of a utility steam generating unit operating at 38 percent efficiency is 9.5 joules per watt hour (9,000 Btu per kilowatt hour).

The efficiency of a steam generating plant refers to its net efficiency. This is the net useful work performed divided by the fuel heat input, taking into account the energy requirements for auxiliaries (e.g., fans, soot blowers, pumps, fuel handling and preparation systems) and emission control equipment. For conventional electric utility units, the total useful work performed is the net electrical output (i.e., net busbar power leaving the plant) from the turbine/generator set. Determination of the net efficiency of a cogeneration unit includes the net electrical output and the useful work achieved by the energy (i.e., steam) delivered to an industrial process. Under a Federal Energy Regulatory Commission (FERC) regulation, the efficiency of cogeneration units is determined from "...the useful power output plus one half the useful thermal output ...," 18 CFR Part 292, §205. Therefore, to determine the process steam energy contribution to net plant output, a 50 percent credit of the process steam heat was selected.

This proposed rulemaking does not include a specific methodology or methodologies for determining the unit net output. The EPA intends to specify such methods in the final rule. Consequently, the EPA requests comment on: (1) the specific methodology or methodologies appropriate and verifiable for determining the net output of a steam generating unit; and (2) whether a fixed percentage credit of 50 percent is representative of the useful heat in varying quality of process steam flows. In addition, the EPA solicits comment on whether the output-based standard in the proposed rule will promote energy efficiency improvements. The EPA acknowledges that a supplemental notice may be necessary should a specific methodology for determining the unit net output be decided upon prior to finalizing this rule.

Based on the analysis showing that SCR can reduce NO_x emissions from coal-fired units to 0.15 lb/million Btu heat input or less, the calculation of an equivalent output-based standard is straight forward using the baseline net plant efficiency. The output-based NO_x standard is computed by using the following equation:

$$E_o(\text{lb/MWh})=E_i(\text{lb/million Btu}) * n * 1000 \text{ kwh/MWh}$$

Using an input-based emission level (E_i) of 0.15 lb/million Btu and a baseline net efficiency (n) of 9,000 Btu/kwh, the resulting output-based limit (E_o) is 1.35 lb/MWh. Based on the available performance data, cost analysis, and the above calculation, the Administrator is proposing today a revised NO_x emission limit for new electric utility steam generating units of 1.35 lb of NO_x/MWh net.

E. Industrial-Commercial-Institutional Steam Generating Units (Subpart Db)

The NO_x standard promulgated in 1986 for industrial steam generating units is based on the performance of LEA and LEA-staged combustion modification techniques. The NO_x control technology examined for revising the current NSPS is SCR in combination with combustion controls. Currently, SCR is considered to be the most effective NO_x control technology for new industrial steam generating units. Based on available performance data and cost analyses, the Administrator has concluded that the application of SCR represents the best demonstrated system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact, and energy requirements) for coal- and residual oil-fired industrial steam generating units.

Under EPA’s regulatory approach, the national average cost effectiveness of additional NO_x control is about $2,000/ton NO_x with a total nationwide increase in annualized costs of about $40 million. Further, EPA’s economic impacts analysis indicates that revised standards based on the adopted regulatory approach would increase product prices by less than 1 percent if all steam cost increases were passed through to product prices. Consequently, the economic impacts of standards based on

EPA's regulatory approach are not expected to be significant.

As discussed above for utility steam generating units, a benefit associated with the selection of EPA's regulatory approach as the basis for the revised NO_x standard is that this regulatory approach expands the control options available by allowing the use of clean fuels as a method for reducing NO_x emissions. The use of clean fuels (i.e., natural gas) may be a cost-effective method of reducing emissions from the coal- and residual oil-fired industrial steam generating units.

Based on available performance data and cost analyses, the Administrator is proposing a revised NO_x emission limit for industrial steam generating units which is applicable regardless of fuel or boiler type, except for one boiler/fuel category. The proposed revision is based on coal-firing and the performance of SCR control technology in combination with combustion controls.

Regarding the revised NO_x emission limitation for industrial units, the Administrator again sought to achieve the best balance between control technology and environmental, economic, and energy considerations and not to limit the control options, but to provide flexibility for cheaper and less energy-intensive control technologies. Due to the cost considerations associated with the application of flue gas treatment on the range of industrial gas-fired and distillate oil-fired units, the Administrator is proposing for industrial steam generating units a revised NO_x emission limit of 0.20 lb/million Btu heat input, except for the category of low heat release rate units firing natural gas or distillate oil which retains the current NO_x emission limit of 0.10 lb/million Btu heat input. The revised limit is the same as the current NO_x emission limit for the category of high heat release rate units firing natural gas or distillate oil. Therefore, under the revised limit, new gas-fired and distillate oil-fired units would not require any additional controls over that required under the current NSPS. Based on the cost impact analysis, it is estimated that by establishing the revised limit at 0.20 lb/million Btu rather than at 0.15 lb/million Btu, the annual nationwide control costs for new industrial steam generating units will be reduced substantially, about 70 percent lower, since the revision would result in no additional controls on gas- and distillate oil-fired units. This revised limit reflects about a 50 to 70 percent reduction in NO_x emissions over the current subpart Db limits for coal-fired and residual oil-fired units.

For low heat release rate steam generating units firing fuel mixtures that include natural gas or distillate oil, the NO_x emission limit would be determined by proration of the NO_x standards based on the respective amounts of each fuel fired when the mixture contains more than 20 percent, based on heat input, of natural gas or distillate oil. Low heat release rate steam generating units firing fuel mixtures that include 20 percent or less of natural gas or distillate oil are subject to the NO_x emission limit of 0.20 lb/million Btu heat input since the use of natural gas or distillate oil in these units is considered to be a clean fuel-based NO_x control technique.

Again, in selecting a single emission limitation that would be applicable regardless of fuel type and boiler type, the Administrator sought to expand the control options available by allowing the use of clean fuels as a method for reducing NO_x emissions. The use of clean fuels (i.e., natural gas) as a method of reducing emissions from these coal-fired and residual oil-fired industrial steam generating units may be a cost-effective approach.

Because the fuel cost differential between gas and coal and access to gas supply (proximity to pipeline) are concerns that may limit natural gas use solely for NO_x control, the control option of SCR in combination with combustion controls that was selected as the basis for the revised NO_x limitation is appropriate since this technology is expected to be an important part of the compliance mix. For residual oil-fired units, SNCR in combination with combustion controls would be able to achieve the proposed limit.

Consideration of an Output-Based Format. This proposed rulemaking for industrial steam generating units does not include an output-based format as is included in today's proposed NO_X revision for electric utility steam generating units. As stated in the discussion on the proposed revision to the utility NSPS, the Administrator has established pollution prevention as one of the EPA's highest priorities. One of the opportunities for pollution prevention lies in simply using energy efficient technologies to avoid generating emissions. In an effort to promote energy efficiency in industrial steam generating facilities, a revised output-based format for the proposed NO_X emission limit was investigated.

The two output-based formats considered were lb NO_X/MWh and lb NO_X/million Btu steam output, the same formats considered for utility steam generating units. The option of lb/MWh, selected for utility units, is more easily understood for utility applications generating only, or mostly, electricity but is unreasonable for industrial units supplying only steam (no electricity generation). The other output-based format option of lb/million Btu steam output would be based on steam output from the boiler and could be applicable to all new industrial boilers. However, this output-based format option, as previously discussed, provides the owners with only minimal opportunities for promoting energy efficiency at their respective facilities. In addition, an output-based format would require additional hardware and software monitoring requirements for measuring the stack gas flow rate (for determining the mass rate of NO_x emissions), steam production rate, steam quality, and condensate return conditions. Instrumentation to conduct these measurements may not generally exists at industrial facilities as they do at utility plants.

The EPA intends to continue to investigate appropriate output-based formats for industrial units which would promote energy efficiency. Consequently, the EPA requests comment on: (1) the specific methodology or methodologies appropriate and verifiable for determining the net energy output of an industrial steam generating unit, (2) the frequency at which the unit's net output or efficiency should be documented, and (3) whether an output-based standard for industrial steam generating units will promote efficiency improvements.

F. Alternate Standard for Consideration

Because of the fundamental change in the format of the NO_x NSPS for electric utility units, the EPA anticipates that there will be numerous concerns and comments concerning the proposed output-based standard. Therefore, the

Administrator is proposing as an alternate to the output-based standard, a traditionally formatted standard of 0.15 lb/million Btu heat input. This input-based NO_X level served as the basis for developing the output-based standard being proposed today. The EPA's preference is to specify an output-based standard in the final rule, but also is proposing the input-based emission level as an alternate in case public comments and/or findings warrant reconsideration of promulgating an output-based standard. Therefore, the EPA also solicits comment on the input-based emission level selected as the basis for the output-based standard, which is achievable using SCR.

The majority of the electric utility steam generators regulated under subpart Da are also regulated under the Title IV Acid Rain Program of the Clean Air Act. The Acid Rain Continuous Emission Monitoring Regulation (40 CFR part 75) requires affected units to install, operate, maintain and quality-assure continuous monitoring systems for SO_2, NO_X, flow rate, CO_2, and opacity. Section 75.64 of part 75 requires quarterly reporting of SO_2, NO_X, and CO_2 emissions in a standardized EDR format specified by the Administrator. The EDR reporting format has been used successfully for Acid Rain Program implementation since 1994. The EDR data from calendar year 1995 were used by the EPA to determine the compliance status of the Phase I-affected Acid Rain units with respect to their allowable annual SO_2 emissions.

At the present time, there is an initiative underway in the Eastern United States to establish an emission trading program for NO_x. The program is called the Ozone Transport Commission (OTC) NO_x Budget Program. Beginning in 1998, the largest sources of NO_x in 13 eastern States will be required to account for their NO_x emissions during the ozone season. Many of the sources in the NO_x Budget Program are electric utility steam generators which are also regulated under NSPS subpart Da and under 40 CFR part 75. Many other NO_x Budget Program sources are regulated under NSPS subpart Db. To implement the NO_x Budget Program, emission data from the affected sources will be submitted electronically, in the EDR format specified under 40 CFR part 75.

At present, any Acid Rain-affected or NO_x Budget Program-affected steam generating unit which is also regulated under NSPS subpart Da or Db must meet the reporting requirements of NSPS in addition to the Acid Rain or NO_x Budget Program reporting requirements. For example, the owner or operator of a subpart Da utility unit would have to submit written NSPS compliance reports each quarter for SO_2, NO_x, and opacity, in addition to the electronic report in EDR format required by part 75.

In many instances, the data reported to meet the requirements of NSPS, the Acid Rain Program, and the OTC NO_X Budget Program are generated by the same CEM systems. The CEM data are manipulated in different ways for the different programs, but very often the NSPS, Acid Rain, and OTC reports are derived from the same data. In view of this, EPA believes it is worthwhile to explore the possibility of consolidating or streamlining the reporting requirements for steam generating units subject to these programs.

The EPA has evaluated different ways in which the reporting burden might be reduced 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 (see Docket Item #II-B-11; "Assessment of Consolidating NSPS Subpart Da and Part 75 Reporting Requirements;" February 25, 1997). The Agency has concluded that the best way to accomplish this would be to allow the SO_2, NO_x, and opacity reports currently required under subpart Da or Db to be submitted electronically in the part 75 EDR format, in lieu of written reports. To implement this electronic reporting option, special EDR record types would have to be created to accommodate the compliance information required by subparts Da and Db.

The EPA believes that in order to derive the full benefit from the electronic reporting option in today's proposal, it should be made available to all subpart Da and

Db affected facilities, including units presently regulated under those subparts, and including affected units that are not regulated under part 75 or the NO_x Budget Program. Today's proposal, therefore, amends §§ 60.49a and 60.49b to allow the owner or operator of any subpart Da or Db facility to choose the electronic reporting option.

IV. Modification and Reconstruction Provisions

Existing steam generating units that are modified or reconstructed after today would be subject to today's revision and to the requirements in the General Provisions (40 CFR 60.14 and 60.15), which apply to all NSPS. Few, if any, changes typically made to existing steam generating units would be expected to bring such steam generating units under the proposed NO_x revisions.

A modification is any physical or operational change to an existing facility which results in an increase in emissions, 40 CFR Part 60, §60.14. Changes to an existing facility which do not result in an increase in emissions, either because the nature of the change has no effect on emissions or because additional control technology is employed to offset an increase in emissions, are not considered modifications. In addition, certain changes have been exempted under the General Provisions (40 CFR §60.14). These exemptions include production increases resulting from an increase in the hours of operation, addition or replacement of equipment for emission control (as long as the replacement does not increase emissions), and use of an alternative fuel if the existing facility was designed to accommodate it, 40 CFR §60.14.

Rebuilt steam generating units would become subject to the proposed NO_X revision under the reconstruction provisions, regardless of changes in emission rate, if the fixed capital cost of reconstruction exceeds 50 percent of the cost of an entirely new steam generating unit of comparable design and if it is technologically and economically feasible to meet the applicable standard, 40 CFR §60.15.

V. Summary of Considerations Made in Developing the Rule

The Clean Air Act was created, in part, "...to protect and enhance the quality of the Nation's air resources so as to promote the health and welfare and the productive capacity of its population..." As such, this regulation protects the public health by reducing emissions of NO_X from electric utility and industrial facilities. 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 proposed revisions will substantially reduce NO_X emissions to the levels achievable using BDT.

The alternatives considered in the development of these proposed revisions are based on emission and operating data received from operating utility and industrial facilities and permitted information for planned utility and industrial facilities. The EPA met with industry representatives several times to discuss these data and information. 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. Of major concern to the industry was the actual numerical limits of the revisions, and whether they would, in effect, dictate the use of only one control option. By using a regulatory approach that expands NO_x control options, the EPA is proposing revised NO_x limits that address their concern.

Another major concern expressed by the utility industry was the potential impact of the revision on existing utility units. Under the General Provisions (40 CFR 60, subpart A) for standards of performance for new stationary sources, an affected facility is defined as a unit which commences construction, modification, or reconstruction after the date of publication of the proposed rulemaking. To date, no existing utility unit has become subject to subpart Da under either the modification or reconstruction provision.

In the revisions, EPA has made an effort to minimize the impacts on monitoring, recordkeeping, and reporting requirements. The proposal does alter the monitoring and recordkeeping requirements (for NO_X only) currently listed in subpart Da by incorporating by reference the monitoring provisions of the Acid Rain Regulation (40 CFR parts 72, 73, 75, 77, and 78). However, 40 CFR part 75 already requires new electric utility steam generating units to comply with these monitoring requirements. In addition, requirements for monitoring of net output, both electrical and process steam, is being added but these are routinely measured by utility boiler owners and operators. Accordingly, the averaging period (i.e., 30-day rolling average) and reporting requirements of subpart Da are not being changed or replaced by incorporating the monitoring provisions of the Acid Rain Regulation. The proposal has no anticipated impact on monitoring, recordkeeping, and reporting requirements for new electric utility steam generating units. This proposal does not alter the monitoring, recordkeeping, or reporting requirements currently listed in subpart Db.

Representatives from other EPA offices and programs are included in the regulatory development process as members of the Work Group. The Work Group is involved in the regulatory development process, and must review and concur with the regulation before proposal and promulgation. Therefore, the EPA believes that the implications to other EPA offices and programs have been adequately considered during the development of these revisions.

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

The cost, environmental, energy, and economic impacts of the proposed revisions are expressed as incremental differences between the impacts of utility and industrial steam generating units complying with the proposed revisions and these units complying with current emission standards (i.e., subpart Da and Db or States' permitted limits).

The revised NO_X standards may increase the capital costs for new steam generating units because the implementation of either SNCR or SCR requires additional hardware.

The EPA estimates that 17 new utility steam generating units and 381 new industrial steam generating units will be constructed over the next 5 years and thus would be subject to the revised standards. The nationwide increase in annualized costs in the 5th year following proposal for the projected new electric utility steam generating units subject to the revised standards is estimated to be about $40 million for utility steam generating units. This impact assumes that all planned coal-fired units remain coal-fired and employ SCR. This represents an increase of about 1.3 mills/kwh in annual costs, or about a 2 percent increase in the cost of generating electricity for these units.

The nationwide increase in annualized costs for new industrial steam generating units subject to the revised standards would be about $41 million in the 5th year following proposal. This is based on the assumption that no affected unit switches fuel type as the result of the revision. This represents an average increase of about 2 percent in the cost of producing steam for new units.

The cost effectiveness of the revised NO_x standards over the existing standards for electric utility units is projected to be about $1,650/Mg ($1,500/ton) of NO_x removed. For industrial-commercial-institutional units, the cost effectiveness of the revised NO_x standards over the existing standards is projected to be about $2,200/Mg ($2,000/ton) of NO_x removed.

The primary environmental impact resulting from the revised NO_x standards is reductions in the quantity of NO_x emitted from new steam generating units subject to the proposed revisions to the NSPS. Estimated baseline NO_x emissions from these new steam generating units are 39,500 Mg/year (43,600 tons/year) from utility steam generating units and 58,400 Mg/year (64,400 tons/year) from industrial steam generating units in the 5th year. The revised standards are projected to reduce baseline NO_x emissions by 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.

National secondary impacts for increased NH_3 emissions are estimated to be about 300 tons/year from utility steam generating units and about 420 tons/year from industrial steam generating units due to the NH_3 slip from SCR or SNCR systems. Ammonia slip tends to be higher from SNCR systems.

There are additional energy requirements associated with SCR systems. Electrical energy is required for booster fans used to overcome the pressure drop across the SCR reactor and related ductwork. This energy requirement is estimated at about 0.4 percent of the boiler output (and was not specifically incorporated into the determination of the baseline operating efficiency of 38 percent).

The goal of the economic impact analysis was to estimate the market response to the proposed changes to the existing standards for NO_x emissions for both utility and industrial steam generating units. The analysis did not quantitatively address the possibility of changing technology, fuel, or capacity utilization in response to the proposed revisions. Therefore, costs and projected impacts may be overestimated.

For utilities, cost estimates for affected facilities expected to be built between 1996 and 2000 were used to project year by year price and quantity changes. The price changes were estimated by assuming that the production weighted average cost changes for the entire industry are passed on to consumers. These estimates resulted in price increases of between 0.01 percent in 1996 and 0.02 percent in 2000. Because the demand for electricity is inelastic, these price changes are projected to result in 0.002 percent (1996) and 0.004 percent (2000) decreases in electricity sales. These numbers are quite small on an industry-wide basis. The price changes on a facility basis, if the cost were completely passed on to the consumer, would be as high as 6 percent; 9 of the 13 facilities would be 1 percent or less. Because the rate structure of utilities generally has reflected the average costs for a utility which includes multiple facilities, such a price increase is unlikely. Therefore, the market impacts for electricity generation are estimated to be small.

For industrial boilers, data by industry for fuel type, furnace type, capacity, and capacity utilization were combined with projections of boiler sales to estimate the number and type of boilers to be replaced. The analysis assumes that a boiler will be replaced with a boiler of the same fuel type, technology, capacity, and capacity utilization. The analysis modeled the response of a firm faced with an added pollution control cost for boiler replacement as a decision concerning the timing of the replacement. The firm replaces an existing boiler when operating costs have increased enough to make the installation of a new boiler cheaper than continuing to operate the old boiler. Added pollution control costs for a new boiler leads the firm to defer the replacement of the existing boiler until the increased cost of operation makes replacement even with the additional pollution control costs the cheaper option. The average replacement delay was very long for small, low-capacity utilization boilers requiring control. Replacement delay may be viewed as an indicator of the severity of impact. For these boilers, the assumption that they will be replaced by a boiler of the same type, size, fuel type, and capacity utilization is questionable in the absence of the proposed revision and even more unlikely in the face of the proposed revision that would add to the cost of small, low-capacity utilization boilers. For affected boilers, the annual compliance cost as a share of annual steam costs ranges from 3 percent for the largest high-capacity utilization residual oil boiler to over 100 percent for the smallest low-capacity utilization spreader stoker boilers.

For industrial boilers, net additions to steam capacity were also estimated. The U.S. Department of Energy's Industrial Demand Module of the National Energy Modeling System (NEMS) was used with U.S. Department of Commerce projections to estimate steam demand through 2010. The yearly increase in demand for steam for each industry corresponds to the required new steam generating capacity needed. The new generating capacity is assumed to reflect estimates of the existing distribution of boilers for that industry by fuel, furnace type, furnace size, and capacity utilization. This leads to an estimate of new capacity affected by the proposed changes in the standards, which ranges from 45 percent for primary metals to 51 percent for paper. The control costs are small for the affected portion of each industry compared to the size of value of shipments for the affected portion. These percentages range from 0.002 percent for miscellaneous manufacturing to 0.8 percent for the paper industry.

The annualized social costs estimated in the economic impact analysis include costs of more stringent control for projected new utility boilers, industrial replacement boilers, and additions to industrial boiler net capacity. For the utility boilers, the estimated cost is $40 million dollars which includes both the control cost ($39 million) and a loss to consumers because of reduced electricity purchases ($1 million). The cost of replacing industrial boilers ($26 million) includes both the higher cost associated with delaying replacement and the higher control cost after replacement. Estimated control costs for projected net new boiler capacity is $49 million. Because of the number of markets involved, no estimates of market changes were made for industries affected by the proposed revision. Therefore, the losses to consumers from reduced purchases of the final goods due to increased costs of steam from industrial boilers were not developed. The assumptions that replacement industrial boilers would be the same as the boilers they replace in the absence of the proposed revisions and that no affected boilers would respond to the proposed revision by changing size, fuel, type, or capacity utilization of affected boilers lead to higher cost estimates. Impacts on fuel markets such as coal are not quantified.

VII. Request for Comments

The Administrator requests comments on all aspects of the proposed revisions. All significant comments received will be considered in the development and selection of the final revisions. The EPA specifically solicits comment on whether, and on what basis, the output-based standard being proposed for electric utility steam generating units under subpart Da should be applied to industrial steam generating units under subpart Db to promote energy efficiency. The EPA recognizes that there are a multitude of applications for which industrial units provide steam, such as basic plant heating and air conditioning, drying, process heating, etc. In addition, industrial units often supply steam for more than one application. As such, the net efficiency of industrial steam generating units can cover a wide range depending on what fraction of the energy delivered to the process actually is used. Unlike utility applications, many industrial applications utilize the heat of condensation. Thus, industrial units would have a much higher net efficiency than a utility application (e.g., 38 percent). Therefore, the output-based standard, as proposed for subpart Da, would be inappropriate for industrial units.

Consequently, the EPA specifically requests comments and information on: (1) how to encourage energy efficiency in industrial applications; (2) whether an output-based format should be applied to industrial steam generating units; (3) the range of net efficiencies applicable to various industrial applications; (4) whether a generic or separate output-based standards should be developed for different industrial applications; (5) the appropriate baseline efficiency; and (6) how the net efficiency of an industrial unit should be determined. For example, the comments might outline the mechanisms or approaches used by industrial facilities to determine the efficiency of various process applications or what fraction of the energy delivered to the process is actually used. Specific comments are requested from all interested parties including State agencies, Federal agencies, environmental groups, industry associations, and individual citizens. Written comments must be addressed to the Air Docket Section address given in the ADDRESSES section of this preamble, and must refer to Docket No. A-92-71.

VIII. Administrative Requirements

A. Public Hearing

A public hearing will be held, if requested, to discuss the proposed revisions in accordance with section 307(d)(5) of the Clean Air Act. Persons wishing to make oral presentations on the proposed revisions should contact EPA at the address given in the ADDRESSES section of this preamble. Oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement before, during, or within 30 days after the hearing. Written statements must be addressed to the Air Docket Section address given in the ADDRESSES section of this preamble, and must refer to Docket No. A-92-71.

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at the EPA’s Air Docket Section in Washington, D.C. (see ADDRESSES section of this preamble).

B. Docket

The docket is an organized and complete file of all the information submitted to, or otherwise considered by, EPA in the development of this proposed rulemaking. The principal purposes of the docket are: (1) to allow interested parties to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process, and (2) to serve as the record in case of judicial review (except for interagency review materials).

C. 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

any revisions to the standard resulting from this proposal as required by the Act. 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 will welcome comments on all 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 proposing the revision to the standards. The economic impact assessment is included in the docket listed at the beginning of today’s notice under SUPPLEMENTARY INFORMATION.

D. Office of Management and Budget Reviews

1. Paperwork Reduction Act. The proposed revisions contain no changes to the information collection requirements of the current NSPS. Those requirements were

previously submitted for approval by the Office of Management and Budget (OMB) during the original development of the NSPS.

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 affecting 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, 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. 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.

3. <u>Regulatory Flexibility Act.</u> 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 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. The Agency certifies that the rule will not have a significant 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 proposed 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, 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 .07 percent. The range of average control cost across industries varies from a low of .004 percent for primary metals to a high of .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. Based on these estimates, EPA certifies that the rule will not have a significant impact on a substantial number of small entities.

4. Unfunded Mandates Act of 1995. Under section 202 of the Unfunded Mandates Reform Act of 1995 ("Unfunded Mandates Act"), signed into law on March 22, 1995, 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, 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 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 EPA's prior consultation with State, local, and tribal officials.

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

a. Statutory authority.

The statutory authority for this rulemaking is identified and described in Sections I and VII of the preamble. As required by section 205 of the Unfunded Mandates Act, and as described more fully in Section III of this preamble, EPA has chosen to propose a rule that is the least burdensome alternative for regulation of these sources that meets the statutory requirements under the Act.

b. Costs and benefits.

As described in section VI of the 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 proposed 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 proposed 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 proposed regulation. A qualitative analysis of industrial boiler replacement raises the possibility that replacement delay due to the proposed 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 5 for a summary of linkages between NO_x emissions and damage categories.

TABLE 5. 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	√√√[4]	√√		√√
Aquatic	√√			√√√
Commercial Biological Systems[5]				

4 Evidence indicates that NO_x can have both positive and negative effects in this category.

5 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

Agriculture	√	√√√		
Forestry		√√		√
Visibility	√√		√√√	
Materials	√√√		√√√	√√√

√ = weak evidence
√√ = limited evidence
√√√ = strong evidence

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.

c. 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 VII C. 4 of the preamble for more detail.

d. Effects on national economy.

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

e. Consultation with government officials.

The Unfunded Mandates Act 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 EPA's response to those comments or concerns. In addition, section 203 of the Act requires that 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, 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, EPA is proposing a higher NO_x emission limit for industrial units than it is proposing today 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 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.

F. Miscellaneous

LIST OF SUBJECTS IN 40 CFR PART 60

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

VII. Statutory Authority

The statutory authority for this proposal 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.

____7/1/97____________ ___________________________

Dated Administrator

PART 60 - [AMENDED]

It is proposed to amend 40 CFR Subpart Da as follows:

* * * * *

1. In §60.41a, the list of definitions is revised to add the following definitions:

Net output means the net useful work performed by the steam generated taking into account the energy requirements for auxiliaries and emission controls. For units generating only electricity, the net useful work performed is the net electrical output (i.e., net busbar power leaving the plant) from the turbine/generator set. For cogeneration units, the net useful work performed is the net electrical output plus one half the useful thermal output (i.e., steam delivered to an industrial process).

* * * * *

2. In §60.44a, paragraphs (a) and (c) are revised to read as indicated below. Paragraph (d) is added that reads 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, * * *

*   *   *   *   *

(c) Except as provided under paragraph (d) of this section, * * *

(d) 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 for which construction, modification, or reconstruction commenced after (date of publication in the Federal Register) any gases which contain nitrogen oxides in excess of 170 nanograms per joule (1.35 pounds per megawatt-hour) net energy output.

*   *   *   *   *

3. In 60.47a, paragraph(k) is added that reads as follows:

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

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure net 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 net 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 net energy output is determined from the net electrical output measured in (k)(1) plus 50 percent of the net thermal output of the process steam measured in paragraph (k)(2).

* * * * *

4. Section 60.49a (i) is revised and a new paragraph (j) is added, to read as follows:

(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 * * *

(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 consistent with the electronic data reporting format specified by the Administrator under § 75.64 (d) of this chapter. 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.

PART 60 - [AMENDED]

It is proposed to amend 40 CFR Subpart Db as follows:

* * * * *

1. In §60.44b, paragraphs (a), (b), (c), and (e) are revised to read as indicated below. Paragraph (l) is added that reads as follows:

60.44b Standard for nitrogen oxides.

(a) Except as provided under paragraphs (k) and (l) of this section, * * *

(b) Except as provided under paragraphs (k) and (l) of this section, * * *

(c) Except as provided under paragraph (l) of this section, * * *

* * * * *

(e) Except as provided under paragraph (l) of this section, * * *

* * * * *

(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 (date of publication in the Federal Register) 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 (0.20 lb/million Btu) heat input; 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.

2. A new paragraph (u) is added to Section 60.49b, to read as follows:

(u) 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 consistent with the electronic data reporting format specified by the Administrator under § 75.64 (d) of this chapter. 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.

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