ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 76

[AD–FRL–5400–2]

RIN 2060–AF48

Acid Rain Program; Nitrogen Oxides Emission Reduction Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule and notice of public hearing.

SUMMARY: The proposed rule would implement the second phase of the Nitrogen Oxides Reduction Provisions in Title IV of the Clean Air Act (''the Act'') by establishing nitrogen oxides (NO_X) emission limitations for certain coal-fired utility units and revising NO_X emission limitations for others as specified in section 407(b)(2) of the Act. The emission limitations will reduce the serious adverse effects of NO_X emissions on human health, visibility, ecosystems, and materials.

DATES: *Comments.* Comments must be received on or before March 4, 1996.

Public Hearing. A public hearing will be held in Washington, DC on February 8, 1996, beginning at 10:00 a.m. Persons interested in presenting oral testimony must contact Peter Tsirigotis at EPA's Acid Rain Division, telephone number (202) 233–9133, by February 2, 1996 to verify arrangements.

ADDRESSES: Comments should be submitted (in duplicate, if possible) to: Air Docket Section (A–131), Attention, Docket No. A–95–28, U.S. Environmental Protection Agency, 401 M Street, SW, Washington, DC 20460.

Public Hearing. The public hearing will be held at the Environmental Protection Agency, 401 M Street, Washington D.C., in the Education Center Auditorium.

Docket. Docket No. A–95–28, containing supporting information used in developing the proposed rule, is available for public inspection and copying between 8:30 a.m. and 3:30 p.m., Monday through Friday, at EPA's Air Docket Section, Waterside Mall, Room 1500, 1st Floor, 401 M Street, SW, Washington, DC 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Peter Tsirigotis, at (202) 233–9133, Source Assessment Branch, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M Street, SW, Washington, DC 20460.

SUPPLEMENTARY INFORMATION: The information in this preamble is organized as follows:

I. Rule Background and Summary

A. Benefits of Reducing NO_X Emissions

The primary purpose of the Acid Rain NO_X Emission Reduction Program is to reduce the multiple adverse effects of the oxides of nitrogen, a family of highly reactive gaseous compounds that contribute to air and water pollution, by substantially reducing annual emissions from coal-fired power plants. Since the passage of the 1970 Clean Air Act, NO_X has increased by about 7%; it is the only conventional air pollutant to show an increase nationwide.

Electric utilities are a major contributor to NO_X emissions nationwide: in 1980, they accounted for 30 percent of the total NO_X emissions and, from 1980 to 1990, their contribution rose to 32 percent of total NO_X emissions. Approximately 85 percent of electric utility NO_X comes from coal-fired plants.

The NO_X emissions discharged into the atmosphere from the burning of fossil fuels consist primarily of nitric oxide (NO). Much of the NO, however, reacts quickly to form nitrogen dioxide (NO_2) and, over longer periods of time, is transformed into other pollutants, including ozone and fine particles. These secondary pollutants are harmful to public health and the environment.

NO_2 and airborne nitrate also degrade visibility, and when they return to the earth through rain or snow (''wet deposition'') or as gases, fog, or particles (''dry deposition''), they contribute to excessive nitrogen loadings to estuaries (''eutrophication''), such as in the Chesapeake Bay, and acidification of lakes and streams.

NO_2 has been documented to cause eye irritation, either by itself or when oxidized photochemically into peroxyacetyl nitrate (PAN). Ozone (O_3), the most abundant of the photochemical oxidants, is a highly reactive chemical compound which can have serious adverse effects on human health, plants, animals, and materials. Fine particles at current ambient levels contribute to morbidity and mortality.

B. Cost-Effectiveness of this Regulatory Action

On April 13, 1995 EPA promulgated the Acid Rain NO_X rule setting emission limits for all Phase I and Phase II dry bottom wall-fired and tangentially fired boilers (Group 1) in the U.S. that combust coal as a primary fuel. The regulation is expected, by the year 2000, to nationally reduce NO_X emissions by an estimated 1.54 million tons per year. The total annual cost of this regulation to the electric utility industry is estimated at 321 million dollars, resulting in an overall cost-effectiveness of 208 dollars per ton of NO_X removed. The nationwide cost impact on electricity consumers is an average increase in electricity rates of approximately 0.21 percent (EPA's Regulatory Impact Analysis, docket item II–F–2).

The proposal would set lower Group 1 emission limits and establish emission limits for several other types of coal-fired boilers (i.e., cyclones, cell burners, wet bottoms, vertically fired, and fluidized bed combustors) for Phase II. The proposal would, by the year 2000, achieve an additional reduction of 820,000 tons of NO_X annually. The annual cost for these additional reductions would be approximately 143 million dollars, at an average cost-effectiveness of 172 dollars per ton of NO_X removed. The nationwide impact on electricity rates of this proposal is an average increase of approximately 0.07 percent, significantly lower than the impacts resulting from the April 13, 1995 rule (see EPA's Regulatory Impact Analysis, docket item II–F–2).

This rule, when promulgated, must meet statutory criteria which relate to cost and performance of existing installations of low NO_X burner technology (LNBT) and to estimates of cost and performance of future installations of a variety of NO_X control technologies. At this time there remain significant uncertainties regarding this information and the best approaches for analyzing it. The information collected to date is incomplete. Resolving these issues is one of the purposes of soliciting public comments on this proposed rule. Information received in the course of this rulemaking may show that no change in the standard for tangentially fired and dry bottom wall-fired boilers may be appropriate and that no standard for cyclones may be justifiable under the statutory criteria.

II. Revision of Phase II, Group 1 Boiler NO_X Performance Standards

A. Statutory Provision

Section 407(b)(2) provides that:

Not later than January 1, 1997, the Administrator may revise the applicable emission limitations for tangentially fired and dry bottom, wall-fired boilers (other than cell burners) to be more stringent if the Administrator determines that more effective low NO_X burner technology is available: Provided, That, no unit that is an affected unit pursuant to section 404 and that is subject to the requirements of [section 407] (b)(1), shall be subject to the revised emission limitations, if any. 42 U.S.C. 76516(b)(2).

Under this provision, the Administrator may revise the applicable NO_X emission limitations for Group 1 boilers to be more stringent if available data on the effectiveness of low NO_X burner technology shows that more stringent limitations can be achieved using such technology. Any revised emission limitations will apply only to Group 1 boilers that first become subject to NO_X emission limitations on or after January 1, 2000. Units with Group 1 boilers that are subject to both SO_2 and NO_X emission limitations in Phase I of the Acid Rain Program are entirely exempted from any revised emission limitations. ''Early-election units,'' i.e., units with Group 1 boilers that are not subject to SO_2 emission limitations until Phase II but that have voluntarily become subject to the NO_X emission limitations by January 1, 1997 and demonstrate compliance with these limitations throughout the rest of Phase I and during the period 2000–2007 are grandfathered from any revised limits until January 1, 2008, at which time any revisions will apply. 40 CFR 76.8.

Section II.B of the preamble summarizes the methodology the Agency has used to evaluate the effectiveness of low NO_X burner technology applied to Group 1 boilers. Preamble Section II.C provides estimates of the emission limitations (in lb/mmBtu) that a substantial majority of units subject to any revised emission limitations can be expected to achieve on an annual average basis. (The revised emission limitations will hereafter be referred to as ''the Phase II, Group 1'' or ''revised Group 1'' emission limitations.) As with units subject to the NO_X emission limitations in Phase I, the designated representative of a unit that is subject to the Phase II, Group 1 emission limitations and cannot meet the applicable emission limitation using low NO_X burner technology may seek to participate in a NO_X averaging plan with other units with the same owner or operator or may petition for a less stringent alternative emission limitation. The Technical Support Document, filed in Air Docket A–95–28 as item number II–A–9, contains a comprehensive description of the methodology and results of the Agency's evaluation of the effectiveness of Group 1 low NO_X burner technology.

Preamble Section II.D addresses the benefits of reducing NO_X emissions. Finally, Section II.E concludes, based on the performance of low NO_X burners (LNBs) on Group 1 boilers and the benefits and relative cost of reducing NO_X by revising the Group 1 emission limitations, that revised emission limitations should be adopted. Section II.F addresses the compliance date for meeting the revised limitations, an issue raised by the regulated utility industry.

B. Methodology

1. EPA's LNB Application Database

The Agency has developed a computerized database containing detailed information on the characteristics and emission rates of coal-fired units with Group 1 boilers on which low NO_X burners (LNBs) have been installed without any other NO_X controls. The Department of Energy (DOE) and Utility Air Regulatory Group (UARG), a major industry association representing utility owners and operators, have assisted EPA in identifying known applications of LNBs on Group 1 boilers.

EPA considered the option of including units on which LNBs have been installed in combination with separated overfire air or other NO_X controls. EPA rejected this approach primarily because, in many instances, the control technology vendor designed the combined system, not the LNB component alone, to achieve the emission performance standard. EPA also decided to exclude units on which LNBs were installed before November 15, 1990, the date of enactment of the Clean Air Act Amendments of 1990. Presumably, Congress was aware of such LNB installations when it set the emission limitations in section 407 (b)(1); but the task here is to determine whether those limitations should be revised because of the availability of more effective LNB, as reflected in the performance of subsequent LNB installations.

The second criterion EPA used in selecting units for evaluating the effectiveness of Group 1 LNB technology was the availability of post-retrofit hourly emission rate data, measured by continuous emission monitoring systems (CEMS), certified pursuant to 40 CFR part 75 (Acid Rain Continuous Emission Monitoring Rule.) The only source of such emission rate data has been the Acid Rain Emission Tracking System (ETS), a computerized information system containing the quarterly emissions reports submitted electronically by utilities under the Acid Rain Program. For Phase I units, ETS provided hourly CEMS data on NO_X emission rates for four quarters of 1994 and the first two quarters of 1995. In most instances, for Phase II units, ETS provided CEMS data for the first two quarters of 1995, only. EPA solicits comment on the appropriateness of using performance data collected by means other than CEMS operated pursuant to 40 CFR part 75.

Using these selection criteria, EPA has compiled a database of coal-fired units with Group 1 boilers, with LNB installations after November 15, 1990, and for which post-retrofit hourly CEMS emission rate data are available. This database presently consists of 24 dry bottom wall-fired boilers (22 Phase I units, 2 Phase II units) and 9 tangentially fired boilers (6 Phase I units, 3 Phase II units). This data set, called the ''EPA LNB Application Database,'' forms the technical basis for EPA's evaluation of the effectiveness (percent NO_X removal) of low NO_X burner technology for Group 1 boilers. EPA plans to continue this analysis as LNBs are installed on more Phase II units and as additional quarters of hourly CEMS data from ETS become available. Additional quarters of ETS CEMS data would be expected to increase the size of this data set considerably since they would include post-retrofit emission rate data for LNB installations performed during summer and fall, 1995.

The EPA LNB Application Database contains the following information for each boiler: nameplate capacity; firing type; pre-retrofit NO_X emission rate; source of pre-retrofit emission rate data; date of boiler shutdown for LNB installation; date boiler resumed normal operations after LNB installation, shakedown, and optimization; hourly

CEMS data from ETS for post-retrofit NO_X emission rates; and hourly data from ETS for boiler operating time and load. EPA contacted utilities to verify the date of boiler shutdown for LNB installation and the date the boiler resumed normal operations after post-retrofit optimization whenever these dates could not be readily ascertained from the hourly CEMS data and other information submitted by utilities to EPA. The Agency solicits comment on what other data would be necessary when assessing whether LNBs are operated in a low-NO_X mode during a certain time period (e.g., percent combustion air introduced through close-coupled overfire air ports in tangentially fired boiler LNB retrofits).

2. Determination of Achievable Annual Emission Limitations

Because the Acid Rain Phase I NO_X Emission Reduction Program goes into effect on January 1, 1996, units in the EPA LNB Application Database have not been required to meet the Phase I NO_X emission rate standards in either 1994 or 1995. For every LNB retrofit there is a period of time, immediately following the retrofit, during which operators learn to operate the new equipment safely and in accordance with the manufacturer's specifications. The operators then learn to optimize NO_X emissions reduction according to each utility's compliance strategy. Performance of LNBs before optimization likely overstates or understates the NO_X reduction achievable by the LNBs. Additionally, continued operation of LNBs to minimize NO_X emissions increases the operation and maintenance (O & M) costs of each LNB retrofit after optimization. Therefore, even though LNB controls are installed, the units may not be operated, throughout the entire post-retrofit period, to sustain the NO_X emission reductions the controls were designed to achieve since this would increase O & M costs when the NO_X reductions are not yet required.

As discussed in EPA's Regulatory Impact Analysis (RIA), plants incur both fixed and variable O & M costs when operating LNBs to lower NO_X emissions in order to meet the NO_X emission limits. The RIA assumes an annual maintenance cost increase of 1.5% of the installed capital cost of the LNB equipment for both dry bottom wall-fired and tangentially fired boilers and a variable cost of 0.04 mills/kWh for dry bottom wall-fired boilers. While the incremental O & M costs given in the RIA are estimated with respect to boiler O & M costs prior to the technology retrofit. The sources of these incremental costs (auxiliary fan power consumption, increased difficulty of maintaining steam temperatures over the load range at reduced excess air levels, higher maintenance demands), suggest that the absence of a requirement to limit NO_X emissions may result in operational changes and higher NO_X emissions. Thus, the average NO_X emission rate over the post-retrofit pre-compliance period may not be representative of achievable LNB performance under actual compliance conditions. On the other hand, it is reasonable to expect that utilities operated their newly installed NO_X controls for some period of time following optimization of the equipment to simulate compliance conditions, perhaps as a dry run or for training purposes. It is intuitive that NO_X reduction techniques which, by their nature, create potentially damaging chemical environments inside boilers and reduce overall plant efficiency when pushed to the highest levels of NO_X reduction performance, could be tested for several weeks at levels which are not sustainable for longer periods of time. According to certain utilities, there is anecdotal evidence that initial performance levels for LNBs cannot be maintained indefinitely on some boilers.[1,2]

In publications and in past rulemakings, DOE and industry have addressed what time period is sufficient for determining an achievable emission limit for a NO_X control technology over the long-term. For example industry has stated "that acceptable results [of long-term performance] can be achieved with data sets of at least 51 days with each day containing at least 18 valid hourly averages" (see docket items II–I–99, Advanced Tangentially-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_X) Emissions from Coal-Fired Boilers; and II–I–100, Demonstration of Advanced Wall-Fired Combustion Modifications for the Reduction of Nitrogen Oxide (NO_X) Emissions from Coal-Fired Boilers).

EPA has adopted the 52-day framework for evaluating the effectiveness of Group 1 LNB technology. The first objective was to identify the lowest average NO_X emission rate each boiler has sustained for at least 52 days, i.e., over a period of 1248 hours during the post-retrofit period when the boiler was operating and valid CEMS data was available. (Such a 1248 hour operating period is generally longer than 52 calendar days since hours during which the boiler did not operate, or operated for only part of the hour are ignored, as are hours for which valid CEM data was not available.) This period, referred to as the "low NO_X period," is assumed to simulate boiler operations under compliance conditions. The next objective was to determine whether the distribution of operating conditions (e.g., load and excess air) during the low NO_X period is representative of actual boiler operating conditions throughout a year. For each boiler in the database, EPA has developed histograms of hourly average NO_X emission rates as a function of load for the low NO_X period and boiler operating load patterns throughout 1994 (see docket item II–A–9). If the operating conditions in the low NO_X period are representative, EPA assumes the boiler can achieve an annual average NO_X emission rate equal to the average emission rate recorded for the period. EPA used these histograms to estimate "load weighted annual NO_X emission rates" based on weighted averages of the average emission rate during the low NO_X period for each operating load level (or "load bin") times the number of hours during 1994 the boiler operated within each load bin.

Some utility commenters have expressed the concern that by not using all the recorded post-retrofit CEM data EPA is not accurately assessing the long-term performance capabilities of LNBs. These commenters believe that all CEM data collected after a fixed shakedown period (30 to 90 days) for equipment optimization and operator training, which is applied universally to all installations, should be used for this assessment. To address this concern, EPA analyzed the CEM data for 2 time periods: (1) a time period that would begin 30 days after LNB installation and include all the post-retrofit data, referred to as the "post-retrofit period," and (2) a time period beginning with the first day of the low NO_X period and continuing beyond 52 days to include all available CEM data throughout the

[1] It was reported that three tangentially fired boilers at Duke Power Company's Allen plant could not maintain design efficiency at full load, while meeting the existing standard of 0.45 lbNO_X/mmBtu. Plant engineers are currently attemping to resolve the problem with a slagging additive. E-mail communication from Robert McMurray, Duke Power, to Doug Carter, USDOE, 11/7/95.

[2] Southern Company reports that two of its Georgia Power Company, McDonough plant tangentially fired units cannot meet their NO_X performance and plant performance guarantees at the same time. Telecommunication between Rob Hardman, Southern Company Services, and Doug Carter, USDOE, 11/3/95.

[3] Based on CREV data taken from EPA's database of uncontrolled NO_X emissions, presented in Appendix A of RIA.

entire post-retrofit period, referred to as the ''post-optimization period.''

One of the primary advantages of using the low NO_X period or the post-optimization period, as defined above, for assessing performance capabilities of LNBs applied to Group 1 boilers is that they explicitly recognize the site-specific nature of the LNB equipment optimization and operator training processes. For some units, both the shakedown of the technology retrofit and operator training proceed smoothly and can be completed within 30 or 60 calendar days. Whereas for other units, particularly units combusting a range of coals and or cycling through load pattern shifts, these processes can take much longer. EPA finds that for dry bottom wall-fired boilers in the database, the beginning of the low NO_X period generally occurs between 2 and 5 months after completion of the LNB retrofit. Not as much variation is seen among the tangentially fired boilers, although only 3 such boilers in the database have more than one quarter of post-retrofit CEM data available.

Utility commenters have also expressed the concern that NO_X emission rate data taken before the Phase I compliance period for Acid Rain SO_2 emission limitations, which began January 1, 1995, may not represent ''normal operating conditions.'' Specifically, in some instances, 1994 Phase I data may not represent the current range of coal quality characteristics being combusted by affected boilers. LNB installations and vendor guarantees are typically tied to operating within a specific range of coals. Moreover, EPA has learned of at least two Phase I boilers which experienced significant increases in NO_X emissions when switching to coal for SO_2 compliance purposes. Other units at the Joppa steam plant, for example, experienced significantly lower NO_X emissions, after switching from eastern bituminous to Powder River Basin coal. These units were dropped from the database for the purposes of assessing LNB performance because the measured percent reduction in NO_X emissions reflects the combined effects of the control technology retrofit and the switch to a more reactive subbituminous coal.

To address these concerns, for each boiler in the database where the 52-day low NO_X period began in 1994, EPA has identified a 52-day low NO_X period for 1995 and compared the average NO_X emission rates for the two periods (see docket item II–A–9). Where these analyses show a noticeable change occurred in NO_X emissions after the beginning of the Phase I SO_2 compliance period, EPA intends to investigate whether switching to low sulfur coal for SO_2 control or whether other operational parameters might explain the difference in LNB performance. Further, EPA solicits comments from the utilities documenting the specific circumstances where the characteristics of coal quality and operating parameters have impacted NO_X emissions.

Also in the Group 1 technical support document (docket item II–A–9), EPA has developed and compared average NO_X emissions rates for the following: low NO_X period, low NO_X period in 1995, post-optimization period, overall post-retrofit period, and the load-weighted annual average NO_X emission rate. The document contains statistical tests of significance on the absolute values of the differences between these alternative ways of estimating the average achievable NO_X emission rate over the long-term. The next section of the preamble summarizes and discusses these comparisons.

EPA has used two complementary analyses to estimate annual average emission rates that can be sustained by LNBs installed on Phase II units with Group 1 boilers and to develop percentile distributions of Phase II units that can comply with various performance standards more stringent than the Phase I standards. The two analyses are described briefly below:

(1) Analysis 1 analyzes actual average emission rates, as measured by CEMS data, achieved by LNBs applied to Phase I units in Phase I and a few Phase II units to calculate the percent reduction achievable by LNBs as a function of uncontrolled emission rate; and

(2) Analysis 2 applies the percent NO_X reduction derived in Analysis 1 to boiler-specific uncontrolled emission rates for the population of units that will be subject to any revised NO_X emission limitations in Phase II in order to determine achievable emission rates for the Phase II, Group 1 population.

The straightforwardness of the retrofit CEMS data analysis (Analysis 1) is appealing in that it reflects actual boiler operating experience. On the other hand, to the extent the Phase I population of boilers is more difficult to retrofit and has higher baseline emission rates and a greater proportion of tight, high furnace temperature boilers than the Phase II population, emission rates based solely on the retrofit CEMS data analysis will understate the achievable annual emission limitations. Analysis 2, which uses a regression model applied to the CEMS data to estimate the percent reduction as a function of uncontrolled emission rates, captures differences in the two populations of boilers.

Utilities complying with Group 1, Phase I reductions for tangentially fired boilers had a spectrum of technologies to choose from in addition to LNBs and some, perhaps due to other NO_X requirements such as title I of the Act, chose to go beyond LNBs in their technology choice. As a result, DOE believes there is the possibility that those units installing LNB were in some way different from tangentially fired boilers in general and, therefore, existing LNB installations may not be representative of how well LNBs will perform on Phase II tangentially fired boilers. EPA seeks comment regarding the representativeness of LNB installations.

Similarly, EPA is aware of no tangentially fired boiler with uncontrolled NO_X emissions exceeding 0.67 lb/mmBtu, which has been retrofit with LNB. DOE believes that about one-fourth of the Phase II tangentially fired boiler capacity exceeds this level of uncontrolled emissions. EPA seeks comment on the ability of LNBs to meet the proposed standards on boilers with uncontrolled NO_X emissions exceeding 0.67 lb/mmBtu, and requests any additional data which relates to this issue.

C. Feasibility of Achieving Revised Phase I Performance Standards

1. Assessment Using Retrofit CEMS Data Analysis

Table 1 presents summary statistics on all known retrofit applications of LNBs to Group 1 boilers, where LNB installation occurred after November 15, 1990 and for which long-term post-retrofit hourly CEMS emission rate data are available. The term ''baseline NO_X rate'' refers to the emission rate as of November 15, 1990 and represents short-term uncontrolled NO_X emissions.

TABLE 1.—SUMMARY OF THE KNOWN LNB APPLICATIONS ON GROUP 1 BOILERS WITH CEMS DATA AVAILABLE

	No. of units	Boiler size (MWe)	Baseline NO_X rate (lb/mmBtu)	Low NO_X period NO_X rate (lb/mmBtu)
Wall-Fired Boilers				
Phase I:				
Mean	22	270.6	0.908	0.418
Range	22	100.0–816.3	0.570–1.340	0.319–0.484
Phase II:				
Mean	2	267.4	0.757	0.354
Range	2	254.3–280.5	0.513–1.000	0.262–0.445
Phase I & II:				
Mean	24	270.3	0.896	0.413
Range	24	100.0–816.3	0.513–1.340	0.262–0.484
Tangentially Fired Boilers				
Phase I:				
Mean	6	230.3	0.653	0.365
Range	6	125.0–324.0	0.630–0.665	0.346–0.387
Phase II:.				
Mean	3	80.5	0.514	0.325
		80.0–81.6	0.478–0.587	0.304–0.363
Phase I & II:				
Mean	9	180.4	0.607	0.352
Range	9	80.0–324.0	0.478–0.665	0.304–0.387

Tables 2 and 3 present detailed data on the 24 dry bottom wall-fired LNB installations and the 9 tangentially fired LNB installations, respectively. Table 2 does not include data for LNB installations that occurred before the cutoff date of November 15, 1990 since these installations occurred prior to the passage of the Act. Table 3 does not include installations at the Joppa Steam plant (owned by Electric Energy Inc.) since these units switched to Powder River Basin coal, nor does it include installations at Lansing Smith, unit 2, (owned by Gulf Power Co.) and Albright, unit 3 (owned by Monongahela Power Co.) since EPA is unsure when during the post-retrofit period these units operated with LNBs without separated overfire air. If EPA is provided information during the comment period about when these latter two units operated with LNBs only, EPA will add them to the database, provided sufficient valid data is available.

EPA recognizes that the amount of compliance NO_X data will be increasing beginning January 1, 1996 as the Phase I units start compliance reporting. EPA will carefully consider the first quarter 1996 data—subject to its timely receipt and required processing by EPA—in preparing the final NO_X rule for the Phase II units and the Group 2 units. Therefore, it is important for quarterly 1996 emission reports to be accurate and timely submitted.

TABLE 2.—KNOWN LNB APPLICATIONS ON WALL-FIRED BOILERS WITH CEMS DATA AVAILABLE

Phase	State	Utility	Plant	Boiler ID	Size (MWe)	LNB retrofit date	Baseline NO_X rate (lb/mmBtu)	Low NO_X period NO_X rate (lb/mmBtu)
1	AL	Alabama Power Co	E. C. Gaston	1	272.0	11/30/94	0.900	0.394
1	AL	Alabama Power Co	E. C. Gaston	2	272.0	04/07/92	.780	.394
1	AL	Alabama Power Co	E. C. Gaston	3	272.0	05/23/93	.800	.408
1	AL	Alabama Power Co	E. C. Gaston	4	244.8	05/21/94	.800	.408
1	KY	Big Rivers Electric Corp	Coleman	C1	174.3	02/07/94	1.340	.436
1	KY	East Kentucky Power Coop Inc	Cooper	1	100.0	03/01/94	.900	.419
1	KY	East Kentucky Power Coop Inc	Cooper	2	220.9	12/31/94	.900	.419
1	KY	East Kentucky Power Coop Inc	HL Spurlock	1	305.2	04/08/93	.900	.402
1	FL	Gulf Power Co	Crist	6	369.8	05/29/94	1.040	.462
1	FL	Gulf Power Co	Crist	7	578.0	01/02/94	1.160	.484
1	IN	Hoosier Energy REC Inc	Frank E Ratts	1SG1	116.6	10/01/94	1.068	.469
1	IN	Hoosier Energy REC Inc	Frank E Ratts	2SG1	116.6	07/01/94	1.090	.430
1	KY	Kentucky Utilities Co	EW Brown	1	113.6	06/16/93	1.000	.466
1	WV	Ohio Power Co	Mitchell	1	816.3	02/01/94	.767	.455
1	WV	Ohio Power Co	Mitchell	2	816.3	01/01/94	.767	.455
1	PA	Pennsylvania Electric Co	Shawville	1	125.0	12/25/93	.990	.438
1	IN	Southern Indiana Gas & Elec Co	F B Culley	2	103.7	05/20/94	1.050	.348
1	AL	Tennessee Valley Authority	Colbert	1	200.0	05/15/94	.800	.397
1	AL	Tennessee Valley Authority	Colbert	2	200.0	05/15/94	.670	.397
1	AL	Tennessee Valley Authority	Colbert	3	200.0	12/24/91	.830	.397
1	AL	Tennessee Valley Authority	Colbert	4	200.0	05/15/94	.860	.397
1	WI	Wisconsin Public service Corp	Pulliam	8	136.0	05/15/94	.568	.319
2	IL	Central Illinois Light Co	Ed Edwards	2	280.5	01/01/93	1.000	.445
2	NV	Sierra Pacific Power Co	North Valmy	1	254.3	06/01/94	.513	.262

TABLE 3.—KNOWN LNB APPLICATIONS ON TANGENTIALLY FIRED BOILERS WITH CEMS DATA AVAILABLE

Phase	State	Utility	Plant	Boiler ID	Size (MWe)	LNB retrofit date	Baseline NO_X rate (lb/mmBtu)	Low NO_X period NO_X rate (lb/mmBtu)
1	GA	Georgia Power Company	McDonough, J .	1	245.0	6/5/95	0.657	0.346
1	GA	Georgia Power Company	McDonough, J .	2	245.0	12/16/94	.657	.346
1	GA	Georgia Power Company	Yates	4	125.0	4/1/95	.630	.387
1	GA	Georgia Power Company	Yates	5	125.0	11/26/94	.650	.387
2	NY	Niagara Mohawk Power Corp ..	Dunkirk	1	80.0	2/1/95	.478	.308
2	NY	Niagara Mohawk Power Corp ..	Dunkirk	2	80.0	1/1/95	.478	.308
2	NY	Rochester Gas & Electric Corp	Rochester 7	4	81.6	3/31/95	.587	.363
1	WI	Wisconsin Electric Power Co ...	Oak Creek	7	317.6	7/15/94	.661	.362
1	WI	Wisconsin Electric Power Co ...	Oak Creek	8	324.0	4/16/95	.665	.362

Units in the same plant that have identical low NO_X period emission rates share a common stack. Under the Acid Rain CEMS Rule, emissions discharged by units sharing a common stack may be monitored by either a single monitor located in the stack or separate monitors located in ducts going from the units to the stack. Similarly, units sharing a common stack frequently have the same baseline NO_X rate.

Virtually all of the baseline NO_X rates in Tables 2 and 3 come from utility-reported data provided to EPA on the Acid Rain Cost Form for NO_X Control Costs for Group 1, Phase I Boilers. Utilities used a CEMS or an EPA Reference Method for measuring these emissions data.

The remaining baseline NO_X rates come from CEMS data reported in monitor certification review (CREV) tests (see docket item II–A–9). These latter data represent average NO_X emission rates calculated from 9 test runs comprising the most recent relative accuracy test audit (RATA). Each RATA test run contains about 25 minutes of CEMS data.

Tables 4 and 5 summarize comparisons of post-retrofit average NO_X emission rates computed using alternative bases: low NO_X period, post-optimization period, low NO_X period in 1995, and overall post-retrofit period following a fixed 30-day start-up period. EPA solicits comment on the relative merits of these alternative bases for determining the performance of low NO_X burners and in particular, the use of a fixed 30-day, 60-day, or 90-day start-up period, universally applied, or some other approach that reflects stabilization of the NO_X control equipment, and how to determine the proper period using the reported hourly emissions data. Summaries of these data are provided below.

TABLE 4.—DRY BOTTOM WALL-FIRED BOILERS

Comparison of average emission rates	Low NO_X period (1994–1995 data)	Post-optimization period	Low NO_X period (1995 data only)	Overall post-retrofit period
Phase I boilers	0.418	0.436	0.437	0.455
Phase II boilers	.354	.368	.354	.385
Phase I & II boilers	.413	.430	.429	.449

TABLE 5.—TANGENTIALLY FIRED BOILERS

Comparison of average emission rates	Low NO_X period (1994–1995 data)	Post-optimization period	Low NO_X period (1995 data only)	Overall post-retrofit period
Phase I boilers	0.365	0.373	0.365	0.375
Phase II boilers	.325	.327	.325	.334
Phase I & II boilers	.352	.358	.352	.361

For each boiler used in the retrofit CEMS data analysis, EPA has identified the low NO_X periods for both 1994 and 1995 as well as examined a plot of daily average NO_X emission rates over the entire post-optimization period. Where these analyses show a noticeable change occurred in NO_X emissions after the beginning of the Phase I compliance period, EPA will investigate whether switching to low sulfur coal for SO_2 control or whether other operational parameters might explain the difference in LNB performance. EPA has examined the relationship between the low NO_X period and the post-optimization period. The average NO_X emission rates for wall-fired boilers for the low NO_X period are lower than the post-optimization period. (No difference is observed for tangentially fired boilers because these two time periods are essentially equivalent in length.) Since the Phase I NO_X Emission Reduction Program is not in effect until January 1, 1996, even though LNBs are installed, the units may not be operated to optimize NO_X emissions throughout the entire post-retrofit period since O&M costs increase when operating LNBs to minimize NO_X emissions. In addition, a literature review indicates that through operational optimization NO_X emissions can be reduced by 10–20%. The existing wall-fired installations of LNBs do show a difference in NO_X reductions, depending on the portion of the post-retrofit data considered. The performance of these units, and therefore the data analysis period, is key to deciding whether the statutory test of ''more effective'' LNBs have been demonstrated. Hence, comment is solicited on defining the best approach to evaluating this post-retrofit data. At this time, EPA has made no final decision on the length of data analysis period.

Recent publications and comments from utility industry representatives indicate that there is concern that 52-day periods (low NO_X periods) may not adequately capture annual dispatch patterns and seasonal variations in demand for electrical power generation. EPA therefore has developed estimates of ''load-weighted annual NO_X emission rates'' based on weighted averages of the average emission rate during the low NO_X period for each load bin times the number of hours during 1994 the boiler operated within each load bin. As summarized below, in less than half of the comparisons, the load-weighted annual NO_X emission rate is no more than 10% above the low NO_X period rate and in the remaining is at or below the low NO_X period rate.

TABLE 6.—COMPARISON OF AVERAGE NO_X EMISSION RATES

[Dry bottom wall-fired boilers]

	Low NO_X period	Load-weighted annual NO_X emission rate
Phase I boilers	0.418	0.409
Phase II boilers	.354	.355
Phase I & II boilers	.413	.405

TABLE 7.—COMPARISON OF AVERAGE NO_X EMISSION RATES

[Tangentially fired boilers]

	Low NO_X period	Load-weighted annual NO_X emission rates
Phase I boilers	0.365	0.325
Phase II boiler	.325	.330
Phase I & II boilers	.352	.327

EPA believes the load-weighted annual NO_X rate estimates address the concern over the adequacy of using 52-day periods. The data show that the annual emission rate projected over the actual dispatch pattern of 1994, results in approximately the same emission rate as the low NO_X period identified during the post-retrofit timeframe. EPA compared the dispatch patterns over the low NO_X period with the actual 1994 annual dispatch pattern and found them to be similar for most boilers. This indicates that the low NO_X period dispatch patterns were representative. Additionally, a strong generic relationship between NO_X and load was not found (see docket item II–A–9). Moreover, the ''52-day periods'' generally span more than two calendar months; they represent NO_X emission rates averaged over 1248 sequential hours during which the boiler was operating and valid CEMS measurements were reported. Hours for which a valid NO_X emission rate measurement is not available (e.g., hours for which substitute data was used for the NO_X emission rate), the unit was not operating, or the unit operated for only part of the hour are not included. Valid CEMS NO_X emission data after such a gap were moved forward and linked to the 52-day low NO_X data chain until there are 1248 hours of NO_X hourly data. The Technical Support Document contains information on the beginning and end of each of the 52-day low NO_X periods as well as the other bases used for estimating post-retrofit average NO_X emission rates.

EPA has tabulated the percentage of time each boiler's daily average NO_X emission rate, during the low NO_X period, was less than or equal to alternative performance standards more stringent than the existing Group 1 NO_X emission limitations. Consistent with the definition of 52-day periods and with the missing data substitution algorithms in the Acid Rain CEMS Rule, a ''daily'' average is defined as the average of a sequential (but not necessarily continuous) set of 24 hours of valid NO_X emission rate measurements excluding missing data results. Tables 8 and 9 show the percentile distributions of Group 1 boilers, by type. EPA estimated the percentage of units in the Group 1 boiler data set that during their low NO_X period in 1994 or 1995, would have complied with various alternative performance standards more stringent than the existing Group 1 NO_X emission limitations.

TABLE 8.—DRY BOTTOM WALL-FIRED BOILERS

	% of Boilers Less Than or Equal to Standard for Low NO_X Period Average				
NO_X Performance Standard (lb/mmBtu)	0.47	0.46	0.45	0.44	0.43
Phase I boilers (22)	95.5%	86.4%	72.7%	72.7%	63.6%
Phase II boilers (2)	100.0%	100.0%	100.0%	50.0%	50.0%
Phase I & II boilers (24)	95.8%	87.5%	75.0%	70.8%	62.5%

TABLE 9.—TANGENTIALLY FIRED BOILERS

	% of Boilers Less Than or Equal to Standard for Low NO_X Period Average				
NO_X Performance Standard (lb/mmBtu)	0.42	0.40	0.39	0.38	0.36
Phase I boilers (6)	100.0%	100.0%	100.0%	66.7%	66.7%
Phase II boilers (3)	100.0%	100.0%	100.0%	100.0%	100.0%
Phase I & II boilers (9)	100.0%	100.0%	100.0%	77.8%	77.8%

Viewed collectively, the various tabulations, analyses, and plots of actual post-retrofit CEMS data suggest to EPA that dry bottom wall-fired boilers with LNBs and tangentially fired boilers with LNBs can easily achieve an annual emission limitation below the current emission limitations of 0.50 lb/mmBtu and 0.45 lb/mmBtu respectively. Estimates of post-retrofit average NO_X emission rates using different bases (i.e., low NO_X period, low NO_X period in

1995, load-weighted annual NO_X rate, and post-optimization period average) are consistent; all of these rates are 14 percent or more below the current emission limitation. Commenters have observed that there is substantial uncertainty concerning the ability of Phase II boilers to meet a lower standard if one considers: (a) units with less than 52 days of monitoring data; (b) the lack of control technology performance data from tangentially fired boilers with uncontrolled emission rates higher than 0.67 lb/mmBtu; and (c) periods of performance monitoring other than the ''low NO_X period.'' Further comment is sought on this issue.

2. Assessment Using Phase II Population Projection Analysis

Figures 1 and 2 display plots of the average NO_X reduction achieved by LNBs, derived from actual retrofit CEMS data, as a function of the short-term uncontrolled NO_X emission rate. (These plots are based on the data in Tables 2 and 3 above.) Also shown in the figures are the results of linear regression models EPA developed to estimate the LNB-controlled emission rate as a function of the short-term pre-retrofit uncontrolled emission rate. EPA has selected the short-term uncontrolled emission rate as the baseline for these analyses because boiler-specific measurements of this variable are available from the CREV test data sets for almost all Phase I, Group 1 boilers and for 69 percent of Phase II, Group 1 boilers. EPA further determined that the Phase II data set (69% of the Phase II population) adequately represents the entire Phase II population by comparing boiler size and age distributions (for details of this analysis, see page 3 of docket item II–A–9).

Based on the information in Figures 1 and 2, EPA estimated the emission rates that can be achieved by Group 1 units subject to any revised emission limitations using LNBs. For both types of Group 1 boilers, EPA used the regression equation with boiler-specific CREV uncontrolled emission rates to develop projections of the LNB-controlled emission rate. For each unit, as shown by the coefficient of correlation, R^2, the regression equation accounts for about 68% (wall-fired) and 67% (tangentially fired) of the variability observed in the data. The regression equations result in NO_X reduction efficiency of low NO_X burners applied to Group 1, Phase II boilers with respect to uncontrolled NO_X emission rate. The NO_X emission reduction percentage then typically ranges from 40 percent to 67 percent for wall-fired boilers and from 35 percent to 47 percent for tangentially fired boilers, depending on each boiler's uncontrolled NO_X emission rate. The lower long-term average NO_X reduction is achieved by low NO_X burners on boilers with lower uncontrolled emission rates. Similarly, the higher long-term average NO_X reduction is achieved by low NO_X burners on boilers with higher uncontrolled emission rates. EPA solicits comment on the representativeness of the reduction efficiency ranges in determining performance of low NO_X burners.

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Figure 1

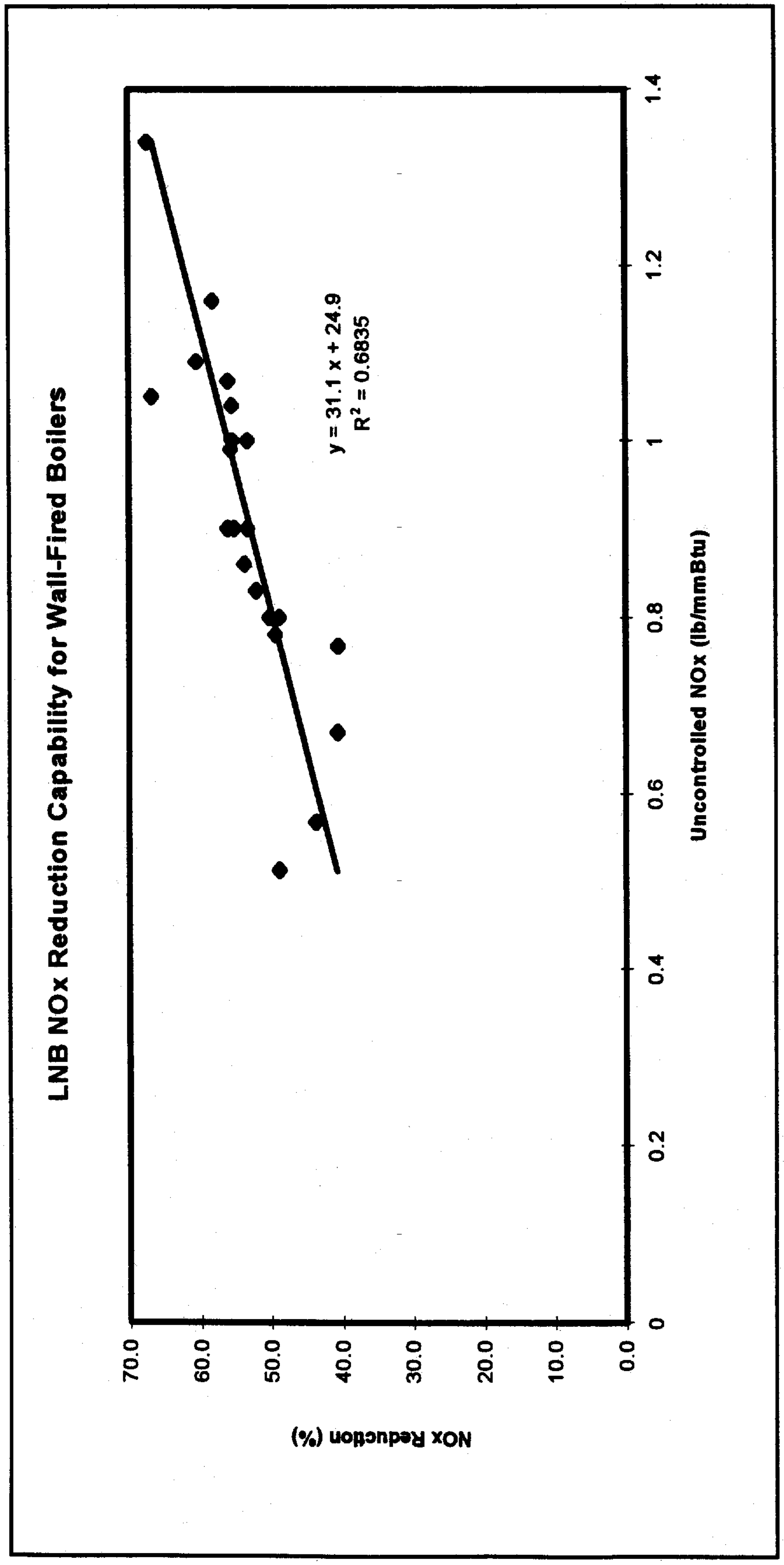
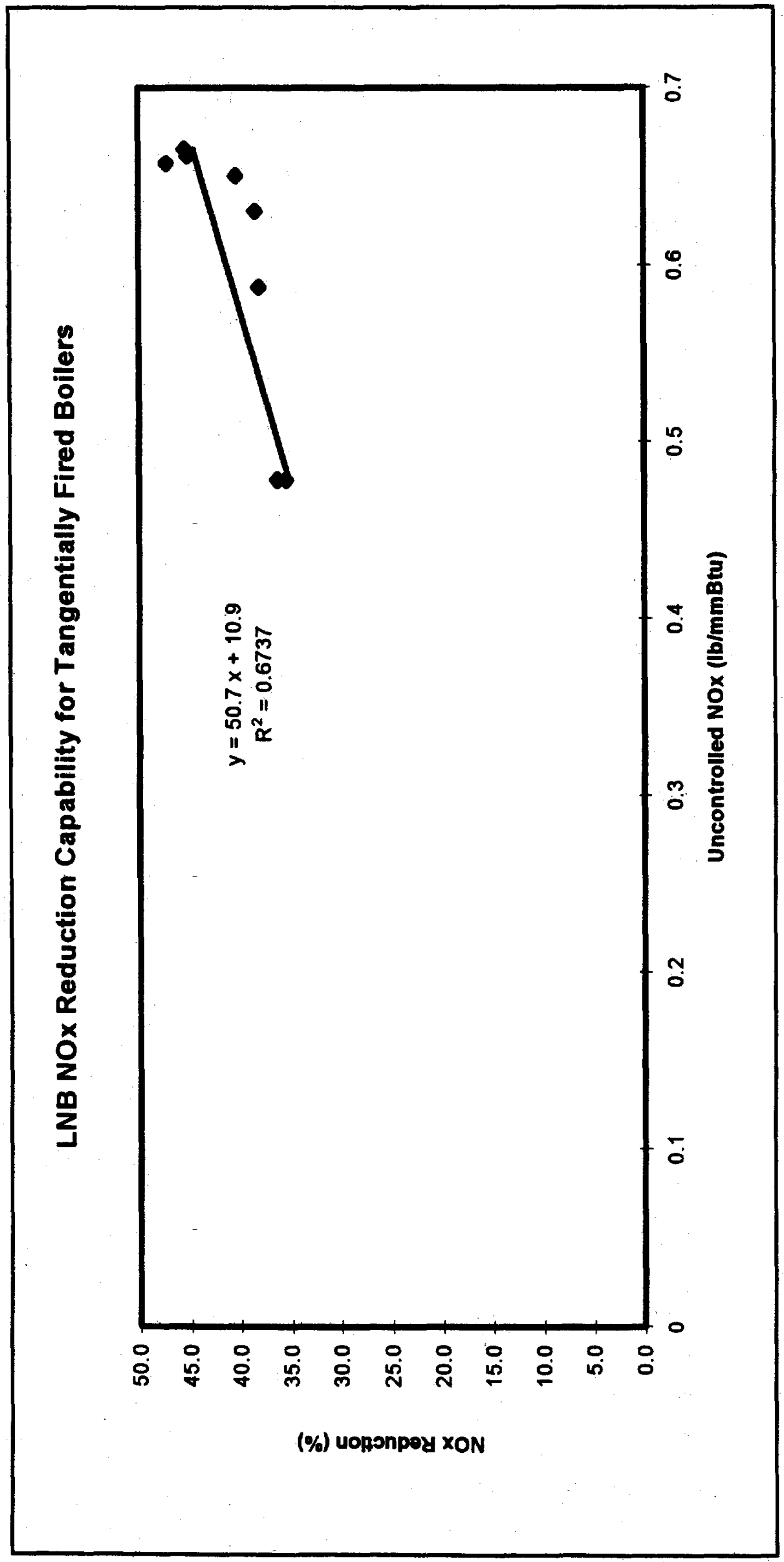

LNB NOx Reduction Capability for Wall-Fired Boilers
y = 31.1 x + 24.9
R² = 0.6835
NOx Reduction (%)
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
0
0.2
0.4
0.6
0.8
1
1.2
1.4
Uncontrolled NOx (lb/mmBtu)

Figure 2



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From these boiler-specific population projections, EPA has developed percentile distributions estimating the number of Group 1 boilers (subject to any revised emission limitations) that can comply with various alternate performance standards more stringent than the current NO_X emission limitations. The resulting distributions of Group 1 boilers by percentile achievement for different performance standards are shown below.

TABLE 10.—PERCENTILE ACHIEVEMENT OF ALTERNATIVE WALL-FIRED BOILER PERFORMANCE STANDARDS

Percentile	Performance standard (lb/mmBtu)
100	0.465
95	0.451
90	0.448
85	0.441
80	0.434

TABLE 11.—PERCENTILE ACHIEVEMENT OF ALTERNATIVE TANGENTIALLY FIRED BOILER PERFORMANCE STANDARDS

Percentile	Performance standard (lb/mmBtu)
100	0.499
95	0.401
90	0.377
85	0.370
80	0.364

The percentile distributions of estimated achievable annual emission limits based on the Phase II population projection analysis indicate that 99.5% of the Phase II dry bottom wall-fired boilers could comply with a revised performance standard of 0.45 lb/mmBtu and 92.3% of the Phase II tangentially fired boilers could comply with a revised performance standard of 0.38 lb/mmBtu. These percentages indicate a better performance than is indicated by the CEMS data analysis. To determine why this difference exists, EPA investigated the uncontrolled NO_X emission rates of Phase I and Phase II boilers. A tabulation of the average uncontrolled emission rates for the Phase I and Phase II populations of Group 1 boilers shows, for both types, that Phase I boilers have higher uncontrolled emission rates.

TABLE 12.[3]—COMPARISON OF PHASE I, GROUP 1 AND PHASE II, GROUP 1 UNCONTROLLED NO_X EMISSION RATES

Boiler type	Phase I average NO_X rate	Phase II average NO_X rate	Percent difference
Dry Bottom Wall-fired .	0.963	0.744	23
Tangentially fired	.652	.536	18

Hence, it is seen that Phase II boilers operate at typically lower uncontrolled emissions rates. As a result, a greater fraction of those boilers are expected to be able to meet a given emission target.

In the preceding discussion, performance data for Group 1 boilers was based on emission data for the low NO_X period, i.e., a period of 52 days of operation as defined above. If the post-optimization period as defined above were used to determine the performance of low NO_X burners, the applicable emission limits would be 0.46 lb/mmBtu and 0.39 lb/mmBtu for wall-fired and tangentially fired boilers respectively. Similarly, if the overall post-retrofit period were used, the applicable emission limits would be 0.48 lb/mmBtu and 0.39 lb/mmBtu for wall and tangentially fired boilers respectively by EPA's calculation. DOE calculates an applicable emission limit of 0.50 lb/mmBtu for wall-fired boilers using the overall post-retrofit period, excluding 2 units considered by EPA, and using a different regression formula than EPA (see docket item, II–D–62, Analysis of Proposed Section 407(b)(2) NO_X Rule, Department of Energy, Staff Paper, December 14, 1995).

If the data used by DOE for the post-retrofit period, using DOE's computations, are representative of performance of wall-fired boilers retrofit with LNBs, then no change in the standard for such boilers would be called for and EPA in the final rule would retain the existing standard for such boilers. An analysis by DOE concluded that only 70% of the affected wall-fired units could meet the proposed emission limit of 0.45 lb/mmBtu (docket item, II–D–62, Analysis of Proposed Section 407(b)(2) NO_X Rule, Department of Energy, Staff Paper, December 14, 1995). EPA seeks comment on the data and the computation used by DOE and on whether the existing standard should be retained for wall-fired boilers.

In the case of tangentially fired boilers, DOE reviewed performance of tangentially fired boilers retrofit with LNBs in addition to those considered by EPA. The emissions data for the units have only recently been reported to EPA under part 75 and have not yet been analyzed. DOE's analysis indicates that 90% of the affected units can meet the current standard of 0.45 lb/mmBtu, but the proposed standard can be met by only 40% (docket item, II–D–62, Analysis of Proposed Section 407(b)(2) NO_X Rule, Department of Energy, Staff Paper, December 14, 1995). If DOE's data are representative of the actual performance of these units, then no change in the standard for such boilers would be appropriate and EPA in the final rule would retain the existing standard for such boilers. EPA seeks comments on the data and on whether the existing standard should be retained for tangentially fired boilers.

EPA recognizes that in several instances the data on which today's proposal is based relate to a limited number of boilers and that analysis of the performance and cost of NO_X controls could benefit from fuller data, involving more units. For example, there are several low NO_X burner technology retrofits on tangentially fired boilers for which the Agency does not yet have available CEM data collected in accordance with part 75 and for which the Agency has not yet evaluated data not reported through part 75 that recently became available. During the comment period the Agency will have the opportunity to examine NO_X emissions data collected from these and other low NO_X burner technology installations. The Agency will also be able to expand the hourly data examined for each boiler listed in Tables 2 and 3 above to include data collected after the second quarter of 1995. In light of additional data that EPA may receive during the comment period, the final rule may establish different Phase II, Group 1 NO_X emission limitations than those proposed today. If the new information is found not to justify revising the emission limitations promulgated in Phase I, EPA will not revise them.

In light of the above discussion about new information that will be received during the comment period, in developing the proposal the Agency considered comment suggesting that the issuance of this proposal should be delayed in order to obtain fuller data on which to base determinations concerning the Phase II, Group 1 emission limitations. However, as discussed above, title IV establishes a schedule for issuance of and compliance

[3] Based on CREV data taken from EPA's database of uncontrolled NO_X emissions, presented in Appendix A of RIA.

with the NO_X emission limitations in this proposal. Section 407(b) requires that any revision of the Group 1 emission limitations (and any Group 2 emission limitations) be established by January 1, 1997 and applicable in Phase II. Establishment by January 1, 1997 of the Phase II NO_X emission limitations under title IV will provide utilities with the information that they need concerning emission requirements for Phase II in order to fashion the most efficient strategies to comply with the Acid Rain NO_X emission reduction program. Under the Acid Rain program, compliance strategies may include: early election plans (where Phase II, Group 1 units elect to comply starting in 1997 with Phase I NO_X emission limitations and avoid any revised Group 1 limitations until 2008); NO_X averaging plans (where NO_X emissions of units with the same owner or operator are controlled to various extents and averaged to meet an overall limit); or alternative emission limitations (where a unit with controls designed, but unable, to meet the standard emission limitation can qualify for a less stringent limitation).

In light of the statutory deadlines under section 407 and EPA's analysis of the presently available data, the Agency has concluded that it has a sufficient basis for proposing revised emission limitations for Phase II, Group 1 boilers. EPA intends to use the comment period on the proposal to gather more data. The Agency stresses that it will welcome, and fully consider in the final rule, any additional data relevant to the proposed emissions limitations.

3. Conclusions

EPA proposes to find that currently available data on the effectiveness of LNB technology on Group 1 boilers demonstrates that ''more effective LNB technology is available'' for both dry bottom wall-fired and tangentially fired boilers under Phase II of the Acid Rain NO_X Emission Reduction Program. Projections developed by applying CEM-based estimated percent reductions to boiler-specific uncontrolled emission rate data for the Phase II population indicate that over 90% of dry bottom wall-fired boilers could individually meet a performance standard of 0.45 lb/mmBtu and over 90% of tangentially fired boilers could individually meet a performance standard of 0.38 lb/mmBtu.

EPA has taken the approach of selecting, as the revised emission limitations achievable by Group 1 boilers, the emission limitations that will be achievable by 90% of the applicable boiler population.

EPA chose to base the proposed emission limitation on the emission rate that a target of 90% of the population will be able to meet because of the flexibility offered by two compliance options available to all Group 1 boilers: (1) emission averaging and (2) alternative emission limitations. Group 1 boilers that install the NO_X control technology and cannot meet the applicable emission limitation on an individual boiler basis may average with other boilers that are below the applicable emission limitation or may petition the permitting authority for a more relaxed emission limit. While the Agency could have assumed that significantly more than 10% of the boiler population could use the averaging or alternative emission limitation option, the Agency maintains that use of the compliance target of 90% reasonably implements the statutory requirement that the emission limitations be based on the degree of emission reduction ''achievable'' through retrofit application of cost-comparable NO_X control technology.

This is analogous to the approach used in setting NO_X emission limitations under section 407(b)(1) for Phase I, Group 1 boilers. Section 407(b)(1) required that the Phase I, Group 1 emission limitations reflect what could be ''achieved using low NO_X burner technology'' (42 U.S.C. 7651f (b)(1)), and, in adopting the presumptive limits set forth in section 407(b)(1) (A) and (B), EPA relied on analysis showing that ''less than 10 percent of the Group 1 units would fail to meet the presumptive limits.'' 60 FR 18758.

TABLE 13.—GROUP 1 BOILER STATISTICS AND EXPECTED RESULTS

For Dry Bottom Wall-Fired Boilers				
Alternative NO_X Emission Standard (lb/mmBtu)	0.46	0.45	0.44	0.43
% boilers estimated to achieve standard based on Phase II population projection method	99.5%	99.5%	87.0%	80.9%
For Tangentially Fired Boilers				
Alternative NO_X Emission Standard (lb/mmBtu)	0.40	0.39	0.38	0.36
% boilers estimated to achieve standard based on Phase II population projection method	95.2%	93.1%	92.3%	80.6%

EPA has estimated that adopting the revised Group 1 performance standards will reduce nationwide NO_X emissions by an additional 200,000 tons annually beyond the annual tonnage reductions under the existing Group 1 emission limitations. When estimating the additional emission reductions from boilers achieving the revised performance standards, EPA has conservatively assumed that LNBs were not applied to any boilers with baseline emission rates at or below the applicable revised performance standard. Thus, these boilers would not contribute to the aggregate estimate of tons NO_X removed.

D. Adverse Effects of NO_X and Benefits of Reduction

Nitrogen oxides (NO_X) emissions result in an unusually broad range of detrimental effects to human health and the environment. NO_X is a primary precursor to ozone formation and therefore is a major component in smog (oxidant air pollution). Atmospheric deposition of nitrogen compounds contributes to the degradation of water quality in certain areas with its ensuing ecological effects. These and other effects, described below, caused by NO_X emissions or their transformation products can adversely affect the environment and human health.

Reducing NO_X emissions from coal-fired power plants by revising the emission limitations for Group 1, Phase II boilers (and by establishing emission limitations for Group 2 boilers) would be expected to produce multiple benefits. Benefits would accrue from reducing ozone within and transported into ozone non-attainment areas, reducing the formation of nitrate particulate matter in the air, reducing ambient levels of NO_2 and PAN gases, reducing excessive nitrogen loadings to the Chesapeake Bay and other estuaries, reducing acid deposition and resulting acidification of lakes and streams, and improving visibility.

1. Formation of Secondary Pollutants, Eutrophication, and Acidic Deposition

NO_X emissions, as discharged into the atmosphere from the burning of fossil fuels, consist primarily of nitric oxide (NO). Much of the NO, however, reacts with organic radicals to form nitrogen dioxide (NO_2) and, over longer periods of time, is transformed into other pollutants, including ozone (O_3) and nitrate fine particles.

Water quality degradation due to excessive nutrients (''eutrophication'') can occur when airborne nitrogen compounds fall directly on water, particularly an estuary, or the surrounding land and enter the water through runoff. Acidic deposition occurs when airborne nitrate compounds, which can be transported over long distances, return to the earth through rain or snow (''wet deposition'') or as gases, fog, or particles (''dry deposition''). While the severity of the damages depend on the composition or sensitivity of the receptor, acidic deposition, according to the 1990 Amendments of the Clean Air Act, ''represents a threat to natural resources, ecosystems, visibility, materials, and public health.''

2. Benefits from Reducing Ozone

Ozone, which is the most abundant of the photochemical oxidants, is formed when NO_X reacts with volatile organic compounds VOCs [4] and sunlight. Heat accelerates this process, so ozone is most severe during the summer months. Ozone is a highly reactive chemical compound which can have adverse effects on human health, plants, animals, and materials. Even 6–8 hours' exposure to elevated levels of ozone can produce decreased lung function, increased airway inflammation, increased sensitivity to lung infection in adults and children, the effects being most pronounced during outdoor work and exercise (see docket item II–A–10; Krupnick and Ozkanynak, 1991; Huang, 1988; Abbey, 1993). Elevated ozone increases the risk and intensity of asthma attacks (Wittmore and Korn, 1980; Krupnick, 1988). The Public Health Service of the National Institutes of Health estimates that, in 1992, 12.4 million Americans had asthma (Benson, 1994).

Ozone at currently occurring levels also inhibits photosynthesis in crops, trees, and plants, which leads to reduced agricultural crop yields, increased susceptibility to pests and disease, and economic losses associated with noticeable leaf damage in ornamental plants. According to the National Acid Precipitation Assessment Program (NAPAP), ozone has been responsible for significant reductions in the annual yields of several domestically important crops: corn, 1%; cotton, soybeans, 7%; and alfalfa, 30% (NAPAP, 1990). Other analyses of five-year data from the National Crop Loss Assessment Network (NCLAN) [5] corroborate this assessment (Sommerville, 1989).

A growing body of scientific evidence indicates that reducing NO_X emissions on a regional basis is a cost-effective approach to achieving the ozone NAAQS the most seriously polluted ozone nonattainment areas of the Eastern U.S.[6] (60 FR 45583, August 31, 1995). These areas have consistently failed to achieve this health-based standard despite up to 20 years of applying controls to sources of VOCs, another ozone precursor, on a localized basis (NRC, 1991). Recent studies of the South, the Northeast Corridor, and the states bordering Lake Michigan conclude that ozone and NO_X transported from attainment areas both within the regions and outside of the regions contribute significantly to ozone non-attainment within the regions (see Southern Oxidants Study, 1995; 60 FR 4217; 60 FR 45580). Modeling performed by EPA for the Ozone Transport Region (OTR), a 12-state region spanning the Northeast Corridor from Northern Virginia to Maine, shows that NO_X emission controls on major sources outside the OTR, primarily power plants in the Midwest, would provide significant incremental reductions, ranging from 12–20%, to polluted areas inside the OTR (US EPA, 1994b). Thirty-two states, as well as areas of Canada, were included in EPA's modeling studies of ozone transport in the Eastern U.S. Achievement of ozone attainment in these regions and protection from ozone-related human health and other effects depend, in part, on reducing NO_X emissions in upwind areas of these regions. EPA notes that 77% of the Group 1, Phase II boilers, and 89% of the Group 2 boilers are located in areas adjacent to and east of the Mississippi River.

3. Benefits from Reducing Particulate Matter

NO_X emissions can not only transform into ozone and other photochemical oxidant gases, they can also react with ammonia, other constituents, and moisture in the atmosphere to form acidic and other nitrate fine particles. Exposure to current levels of fine particles in the air has a wide range of health and other adverse effects, ranging from higher cleaning expenses effects on morbidity and mortality (see Schwartz, 1994; Fairday, 1990; and US EPA, 1995b). Nitrates are considerably smaller than 10 microns and are part of the PM_{10} particulate matter subclass $PM_{2.5}$, called ''fine particles.'' Documented illnesses caused by exposure to fine particles, particularly over extended periods of time, include: various respiratory diseases, eye irritation, aggravation of existing cardiovascular disease, and lowering the body's resistance to carcinogenesis and foreign materials.

Adverse respiratory health effects can also occur when people, particularly individuals in sensitive subpopulations, breathe aerosols (Thurston, 1989). Acidic aerosols include solid particles and liquid droplets suspended in the air that are generated when NO_X transforms into nitrates. One of the benefits of additional NO_X emission reductions would be health and economic benefits associated with reductions in the formation of nitrate fine particles.

4. Benefits from Reducing NO_2

NO_2 is a brownish gas that has been documented to cause eye irritation in people, either by itself or when oxidized photochemically in the presence of VOCs and sunlight into PAN (Schwartz et al., 1988). Elevated levels of NO_2 have also been documented to cause lower respiratory illness (LRI) in otherwise normal children, making them suffer from chronic cough, persistent wheezing, and/or chronic phlegm (Neas, 1991). Persons with pre-existing chronic obstructive pulmonary disease (COPD), estimated to be 14 million in the U.S. (U.S. Department of Health and Human

[4] Like NO_X, volatile organic compounds (VOCs) are emitted directly into the atmosphere from a combination of man-made sources (burning of fossil fuels in utility and industrial boilers, motor vehicle emissions, hydrocarbon releases from dry cleaning and other industrial processes) and natural sources (mostly vegetation).

[5] NCLAN was established by EPA during the 1980s for controlled field tests to develop dose-response relationships between ozone concentrations and crop yield.

[6] See Regional Ozone Modeling for Northeast Transport (ROMNET), EPA Doc. EPA–450/4–91–002a (June 1991), and Chu, S.H., E.L. Meyer, W.M. Cox, R.D. Scheffe, ''The Response of Regional Ozone to VOC and NO_X Emissions Reductions: An Analysis for the Eastern United States Based on Regional Oxidant Modeling,'' Proceedings of U.S. EPA/AWMA International Specialty Conference on Tropospheric Ozone: Nonattainment and Design Value Issues, AWMA TR–23, 1993.

Services, 1990), and asthmatics are more likely to suffer from respiratory ailments or chronic illness (decreased lung function and increased risk of lung infection) caused by exposure to NO_2 than the general population.

5. Water Quality Benefits

Atmospheric deposition of nitrates can be a significant factor in the degradation of water quality and its associated health risks and damaging ecological effects. Various forms of nitrogen have been measured as wet and dry deposition falling on the Chesapeake Bay and its watershed. Eutrophication, which results from excessive nitrogen loadings, can cause adverse ecological effects. Impacts range from nuisance algae blooms to the depletion of oxygen with resultant fish kills. Approximately 25–40% of total nitrogen entering the Bay and other estuaries is a result of atmospheric deposition (US EPA, 1994a).

A study of the Chesapeake Bay, performed under a Congressionally mandated program to evaluate the effects of atmospheric deposition to pollutant loadings in the Great Water Bodies of the U.S., determined that the majority of airborne nitrogen compounds over the Bay are emitted by power plants and motor vehicles (US EPA, 1994a). Reductions in NO_X emissions from power plants are substantially less expensive to implement than alternative controls for reducing nitrogen loadings to the Bay from point (wastewater plants) and area (farms, animal pastures) sources. Such alternatives are presently being considered by the States of Maryland, Pennsylvania, and Virginia, and the District of Columbia in order to achieve a 40%-reduction in nutrient supplies to the Bay by the year 2000, to which these jurisdictions have committed. The average cost-effectiveness of these other controls are: chemical addition or biological removal of nitrogen from wastewater processing ($4,000 to over $20,000/ton nitrogen removed) and ‘‘management practices’’ to reduce nitrogen from fertilizers, animal waste, and other nonpoint sources ($1,000 to over $100,000/ton of nitrogen removed) (Camacho, 1993; Shuyler, 1992). By comparison, the average cost-effectiveness of LNB applied to Group 1 coal-fired boilers in this proposal is estimated to be $250/ton of NO_X removed, which corresponds roughly to $500/ton of nitrogen removed. (Similarly, NO_X controls applied to Group 2 coal-fired boilers have an average cost-effectiveness of $150/ton, or roughly $300/ton of nitrogen removed.)

6. Visibility and Acidic Deposition Benefits

Nitrogen dioxide (NO_2) and nitrate particulates also contribute to pollutant haze, which impairs visibility and can reduce residential property values as well as revenues generated by tourism, national parks, etc.

Atmospheric deposition of nitrogen compounds is an important component in the acidification of lakes and streams. Recent scientific studies indicate the amount of nitrogen that can be sequestered in certain watersheds by biological and other processes is limited (US EPA, 1995). As these watersheds approach nitrogen saturation, nitrates can begin to leach into surface waters, accelerating the process of long-term chronic acidification. Further, according to EPA’s Acid Deposition Standard Feasibility Study Report to Congress, ‘‘both sulfates and nitrates originating from atmospheric deposition can contribute significantly to episodic acidification events’’ (US EPA, 1995:14). Episodic acidification occurs when highly acidic water, toxic to fish, enter lakes and streams during storm flow or snowmelt runoff, often during spawning season in the Spring. Acidified ecosystems can show signs of recovery, however, following reductions in acidic deposition rates. Environmental modeling performed for EPA’s Acid Deposition Standard Feasibility Study predicts benefits to varying degrees in watersheds where atmospheric deposition of acidic compounds has been and will continue to be reduced (US EPA, 1995). One study conclusion is that additional limits on nitrogen deposition would likely produce a two-fold potential benefit by reducing acidic deposition rates and lengthening the average time for watersheds to reach nitrogen saturation (US EPA, 1995:56).

Efforts are currently underway to further investigate the mechanisms by which nitrogen deposition directly impacts or works with other pollutants to damage structural and other materials (NAPAP, 1993).

E. Revised Emission Limits for Group 1 Boilers

EPA proposes, for the following reasons, that the Administrator should exercise her discretion under section 407(b)(2) to revise the emission limitations for Group 1 boilers to be more stringent. As discussed above, analysis of the performance of LNBs on Group 1 boilers shows that more effective low NO_X burner technology is available. Group 1 boilers subject to NO_X emission limitations starting on or after January 1, 2000 are capable of achieving, with LNBs: 0.45 lb/mmBtu for dry bottom wall-fired boilers and 0.38 lb/mmBtu for tangentially fired boilers. Further, revision of the limitations would result in additional NO_X reductions of about 200,000 tons annually. In light of the significant, adverse impacts of NO_X emissions on human health and the environment, these additional reductions would be beneficial. Finally, revision of Group 1 emission limitations would be a cost-effective way of achieving these reductions, relative to alternative pollution control strategies. Therefore, EPA proposes to adopt the revised Group 1 emission limitations.

F. Compliance Date

Industry has expressed concern about the regulated utility community’s ability to begin the Phase II program on January 1, 2000, should EPA decide to revise the Group 1 emission limitations (see docket A–92–15, item VIII–A–1, Brief of Petitioners, July 1, 1994). No statutory provision exists for extension of the Phase II compliance deadline analogous to the 15-month Phase I compliance extension authorized by section 407(d) of the Act. Since four times as many Group 1 boilers are subject to NO_X emission limitations in Phase II as are in Phase I, industry spokespersons are concerned that utilities may have barely enough time to procure LNB technology, schedule outages, and install and test equipment, consistent with system reliability (see docket A–92–15, item VIII–A–1, Brief of Petitioners, July 1, 1994).

Actual experience to date in preparing for Phase I, however, indicates the anticipated technology shortage may not materialize. EPA has received only 9 requests for the Phase I compliance extension. Moreover, EPA has already received several inquiries about early election for compliance with NO_X emission limitations in Phase I by units subject to NO_X emission limitations starting in Phase II. This suggests that an adequate supply of Group 1 LNB technology is available.

EPA solicits comments from utilities and LNB technology vendors on their ability to meet the statutory Phase II compliance date. Comments advocating a compliance date extension should describe specific problematic situations associated with the procurement and/or installation of LNB technology and differentiate between site specific and generic industry concerns.

EPA also requests comment on the need for a compliance extension for boilers that must meet a more stringent title I NO_X limit on a date certain after the statutory title IV Phase II compliance date, and on whether there is a legal basis for such extension.

G. Definition of Coal-Fired Utility Unit

EPA proposes to revise the definition of ''coal-fired utility unit'' as it applies to Phase II units. Under the current provision in § 76.2, any Phase II unit for which combustion of coal (or coal-derived fuel) is more than 50.0 percent of the unit's annual heat input in 1995 is a ''coal-fired utility unit'' and is therefore subject to the Acid Rain NO_X emission limitation for the unit's boiler type. However, the current definition raises the question of whether the Acid Rain NO_X emission limitations apply to a unit that is designed to combust, and has previously combusted, coal but is shutdown for all of 1995 and resumes operation thereafter. EPA sees no basis for treating such a unit differently from another unit that is designed to combust coal and operates during 1995 and thereafter.

Consequently, EPA proposes to revise the ''coal-fired utility unit'' definition to include any Phase II unit that does not combust any fuel that results in the generation of electricity during 1995 but has combusted in any year during 1990–1995 fuel that comprised more than 50 percent coal and that resulted in the generation of electricity.

III. Control of NO_X Emissions From Group 2 Boilers

A. Description of Group 2 Boilers

Under section 407(b)(2) of the Act, EPA is required to establish NO_X emission limitations (on a lb/mmBtu annual average basis) for Group 2 boilers including wet bottom wall-fired boilers, cyclones, units applying cell burner technology, and all other types of utility boilers not classified as dry bottom wall fired and tangentially fired boilers, by January 1, 1997. In the following sections, information is presented on the basic design, population, and estimated uncontrolled NO_X emissions from each of these boiler types. For details pertaining to this information, please refer to the Group 2 technical support document (see docket item II–A–2, Investigation of Performance and Cost of NO_X Controls as Applied to Group 2 Boilers, pp. 2–1 to 2–4) and EPA's Regulatory Impact Analysis (see docket item II–F–2).

1. Basic Designs of Group 2 Boilers

Cell Burner Boilers. These boilers are dry bottom units that consist of arrays of two or three closely-spaced circular burners in a vertical assembly, i.e., the cell, mounted on opposed walls of the furnace. Furnaces equipped with cell burners fire coal, oil, and natural gas. Generally, in these furnaces, the close spacing of circular burners results in hotter burner zones than those in dry bottom wall-fired furnaces equipped with circular burners that are not clustered. As a consequence, cell burner equipped boilers have high combustion efficiencies but typically generate high levels of NO_X emissions.

Cyclone Boilers. Cyclone boilers are wet bottom units fired on crushed coal. In these boilers, fuel and air are burned in horizontal water-cooled cylinders, called cyclones. The arrangement of coal burners and secondary air ports in a cyclone results in a spinning, high temperature flame. Relatively high furnace temperatures in a cyclone cause conversion of ash into a molten slag. This slag collects on the cylinder walls and then flows down the furnace walls into a slag tank located below the furnace. As a result of high furnace temperatures, cyclone boilers are generally characterized by high NO_X emissions. Though cyclone boilers are wet bottom boilers, they are not included in the wet bottom category due to their unique firing pattern as explained above.

Wet Bottom Boilers. This type of boiler includes several firing configurations (e.g., wall fired and vertically fired) and is characterized by wall mounted burners, similar to those in dry bottom units. However, the furnace temperatures in these boilers are generally higher than those in corresponding dry bottom units, thereby resulting in furnace zones hot enough to melt the ash. Slag produced by melting of the ash flows down and is tapped off from the bottom of the furnace.

Vertically Fired Boilers. In these boilers, conventional circular burners or coal and air pipes are oriented downward, rather than horizontally as in wall-fired boilers. In general, these boilers have more complex firing and operating characteristics than wall or tangentially fired boilers. Several vertically fired furnace designs are in operation today, including top-fired, roof-fired and arch-fired configurations.

In top-fired and roof-fired boilers, burners are mounted on the roof of the furnace and combustion gases flow downward and through a superheater located at the bottom of the furnace. In arch-fired boilers, burners mounted on lower furnace arches generate long, looping flames and hot combustion gases discharge up through the center.

It should be noted that the vertically fired category consists of only dry bottom boilers. Wet bottom vertically fired boilers are included in the wet bottom boiler category, along with wet bottom wall-fired boilers.

Stoker Boilers. Coal-fired stoker boilers range in size from 2,000 lb/hr to approximately 500,000 lb/hr steam generation capacity. Practical design considerations limit stoker size and maximum steam generation rates depending upon the type of fuel being fired. The major types of stoker boilers include spreader stokers, underfed stokers, and overfed stokers, which reflect the differences in the manner of coal injection into the boiler. Additional stoker types or subcategories (including traveling or chain grate, vibrating grate, and dumping grate) reflect different methods of removing ash from the combustion bed surface or grate.

FBC Boilers. Fluidized-bed combustors (FBC) range in size from industrial boilers that produce less than 50,000 lb/hr of steam up to utility-type boilers that generate hundreds of megawatts of power. In these boilers, crushed coal in combination with some inert material (e.g., silica, alumina, or ash) and air is maintained in a turbulent suspended ''fluidized'' state and combusted at relatively low furnace temperatures. FBC designs have been classified as either bubbling or circulating, depending on the velocity of the solids moving through the combustor. Additionally, these boilers can be designed to operate under atmospheric or pressurized conditions, resulting in atmospheric FBC (AFBC) or pressurized FBC (PFBC) systems.

2. Characterization of the Group 2 Boiler Population and Uncontrolled NO_X Emissions

Table 14, shown below, exhibits the differences in boiler types with respect to population, nameplate capacity, size, and estimated uncontrolled NO_X emissions. This table has been developed using the information presented in the EPA Group 2 Boiler Database found in Appendix A of the Group 2 technical support document (see docket item II–A–2, Investigation of Performance and Cost of NO_X Controls as Applied to Group 2 Boilers). Note, however, that this table excludes certain units that are not expected to be in operation beyond the year 2000. A listing of these units can be found in EPA's RIA (docket item II–F–2). EPA requests comment on the data presented in this table.

TABLE 14.—CHARACTERIZATION OF GROUP 2 BOILERS

Boiler type	Population		Nameplate capacity		Size mean range		Estimated uncontrolled NO_X	
	(Units)	Percent	(MWe)	Percent	(MWe)	(MWe)	(Tpy)	Percent
Cell-burner	35	16	24,060	36	690	38–1,300	668,000	38
Cyclone	88	41	27,495	41	310	33–1,150	732,000	41
Wet-bottom [7]	38	18	8,576	13	226	29–544	277,000	16
Vertically Fired [8]	29	13	4,612	7	159	50–254	97,000	5
Stoker	21	10	1,083	2	52	32–79	3,000	~0
FBC	6	2	889	1	148	75–194	2,000	~0
Total	217	100	66,715	100			1,779,000	100

B. NO_X Control Technologies for Group 2 Boilers

1. Available Group 2 Boiler NO_X Control Technology

EPA considers a NO_X combustion modification technology to be available for a type of Group 2 boiler if there exists at least one full-scale demonstration or commercial application of that technology on that type of boiler. Further, if a utility has successfully applied a combustion control technology on a full-scale boiler of that type, then that technology is also considered to be available. EPA considers a NO_X post-combustion control technology to be available for each type of boiler if it has been demonstrated on any full scale boiler.[9] Because these latter controls are applied downstream of the combustion process, they do not affect combustion and can be applied to any boiler type.

Shown in Table 15 are full-scale NO_X control retrofits that have been installed or will be installed in the very near future in the U.S. Using the information in this table, the following NO_X control technology and Group 2 boiler type combinations are considered to be available.

- Plug-in and non plug-in combustion controls on cell burner boilers.
- Coal reburning on cyclone boilers.
- Gas reburning on cyclone boilers.
- Selective non-catalytic reduction (SNCR) on all coal-fired boilers.
- Selective catalytic reduction (SCR) on all coal-fired boilers.
- Combustion controls on wet bottom and vertically fired boilers.

TABLE 15.—GROUP 2 BOILER NO_X CONTROL TECHNOLOGY DEMONSTRATIONS AND COMMERCIAL RETROFITS

NO_X control technologies	Boiler type	Number of full-scale or commercial retrofits	Retrofit size range (MWe)
Plug-In Retrofits (Low NO_X Combustion Controls)	Cell-Burner	7	555–780
Non Plug-In Retrofits (Combustion Controls and Wall Replacements).	Cell-Burner	3	630–760
Coal Reburning	Cyclone	1	110
Gas Reburning	Cyclone	2	33–114
SNCR	Cyclone	1	138
	Wet Bottom	1	321
	Vertically Fired	1	100
SCR	Cyclone	1	320
	Wet Bottom	1	[10] 80 (321)
Combustion Controls	Wet Bottom	1	217
	FBC	6	75–194
	Vertically Fired	4	100–152

Note that no NO_X control demonstrations were found for stoker boilers covered under title IV of the Act.

2. Description of Group 2 Boiler NO_X Control Technologies

Basic descriptions of the NO_X control technologies that EPA considers available for Group 2 boilers are provided in this section. For more details on these technologies and their applications on Group 2 boilers, please refer to the Group 2 technical support document (see docket item II–A–2, Investigation of Performance and Cost of NO_X Controls as Applied to Group 2 Boilers, pp. 3–1 to 3–36) and 57 FR 55648–49 (November 22, 1992). Additional information can be found in site reports written by EPA personnel who inspected certain Group 2 boilers applying NO_X control technologies (see docket items II–B–1 through II–B–6).

Combustion Controls for Cell Burner Boilers. In plug-in combustion control retrofits, all existing cells in a furnace are replaced by either low NO_X burners or by using the existing cell burner openings to install low NO_X burners in combination with overfire air ports. To date, these controls have been applied to two-nozzle cell burners, and their

[7] NO_X controls for wet bottom boilers of any firing design have to be designed to not perturb furnace temperatures and thereby not disturb slag tapping capability. Thus from the standpoint of NO_X control, wet bottom boilers of all firing designs, including wall-fired and vertically fired boilers, are grouped in one category: wet bottom boilers. The wet bottom category in the above table includes several firing configurations, viz., 20 front wall fired, 5 opposed wall-fired, 4 arch fired, 3 turbo fired, and 6 roof fired.

[8] The dry bottom, vertically fired category includes the following designs: 5 arch fired, 12 roof fired, 3 top fired and 13 vertically fired.

[9] The manufacturer of cyclone boilers, in a recent letter to EPA dated October 27, 1995, stated that a significant portion of cyclone boilers in the US cannot achieve 50% reduction in NO_X emissions using coal reburn.

[10] SCR system was installed only in one of four ducts of the 321 MWe boiler, and only one quarter of the total unit's flue gas volume passes through the SCR system (equivalent to 80 MWe).

installation requires no modifications to boiler pressure parts and only minor modifications to burner piping. EPA believes that this technology can be modified and adapted to three-nozzle cell burner configurations.

Non plug-in combustion control retrofits have been applied to all types of cell burner configurations. With this approach, portions of the furnace walls containing cells are replaced by new walls containing low NO_X burners or low NO_X burners with overfire air. This technology has been applied to both two-nozzle and three-nozzle cell burner configurations and essentially converts the cell-burner firing arrangement to a conventional wall-fired arrangement.

Reburning. Reburning is a low NO_X combustion technology in which part of the main fuel heat input is diverted to a location above the main burners, thus creating a secondary combustion zone called the reburn zone. Completion or overfire air (OFA) is added above the reburn zone to complete the burnout of the reburn fuel. The reburn fuel can be natural gas, pulverized coal, or oil. The arrangement of injection of reburn fuel and OFA causes the reburn zone conditions to be sub-stoichiometric. As flue gas passes through this sub-stoichiometric zone, part of the NO_X formed in the main combustion zone is reduced by radical fragments and converted to molecular nitrogen. The source for these radical fragments is the combustion gas from the secondary, or reburning, fuel fired in reburn injectors or burners.

Selective Non-catalytic Reduction (SNCR). SNCR is a post-combustion NO_X control technology that injects a reducing agent (urea, ammonia, or cyanuric acid) into the boiler's flue gas for NO_X control. The reducing agent reacts with NO_X in the flue gas to form molecular nitrogen and water. The SNCR reactions take place in a temperature range of 1600 to 2100 °F.

Selective Catalytic Reduction (SCR). SCR is a post-combustion NO_X reduction process in which ammonia is added to the flue gas, which then passes through layers of a catalyst. The ammonia and the NO_X react on the surface of the catalyst, forming molecular nitrogen and water. The temperature window for SCR reactions is between 575 and 750 °F.

Combustion Controls for Vertically Fired, Wet Bottom, and FBC Boilers. Combustion staging concepts are currently being applied at vertically fired boilers (see docket items II–A–2, Investigation of Performance and Cost of NO_X Controls as Applied to Group 2 Boilers, p. 3–18; II–B–4; and II–B–6). Specifically, these concepts involve redistributing coal and primary air flows to establish a primary fuel rich zone and redistributing secondary air flow to create a secondary fuel rich zone. Burnout is completed by providing staged burnout air. A combustion staging system using two levels of overfire air is being installed in the Fall of 1995 by a utility on a wet bottom boiler (see docket items II–A–2, Investigation of Performance and Cost of NO_X Controls as Applied to Group 2 Boilers, p. 3–18; and II–D–30). All the FBC boilers subject to section 407(b)(2) already have combustion controls.

C. Statutory Requirements

Section 407(b)(2) of the Act requires the Administrator to set, by January 1, 1997, annual emission limitations for NO_X for units with Group 2 boilers, i.e., wet bottom wall-fired boilers, cyclones, units applying cell burner technology, and ''all other types of utility boilers''. 42 U.S.C. 7651f(b)(2). The Administrator must base these emission limitations on

> the degree of reduction achievable through the retrofit application of the best system of continuous emission reduction, taking into account available technology, costs, and energy and environmental impacts; and which is comparable to the costs of nitrogen oxides controls set pursuant to [section 407] (b)(1). *Id.*

Section 407(b)(2) thus provides instruction to the Administrator for setting Group 2 emission limitations based on what reductions can be achieved by the best continuous control technologies. First, the costs of the control technologies on which the Administrator bases Group 2 emission limitations must be ''comparable'' to the costs of low NO_X burner technology as applied to Group 1 boilers. The statute does not explain what is meant by ''comparable'' costs or how ''costs'' are to be measured. These matters are left to interpretation by the Administrator in applying section 407(b)(2). *See Chevron, U.S.A.* v. *NRDC,* 467 U.S. 837, ____ (1984). However, the legislative history provides some assistance in the interpretation of the comparable-cost requirement.

> As explained by the Conference Report to the Clean Air Act Amendments of 1990,
>
> Section 407(b)(2) is intended to incorporate a portion of the Senate Environment and Public Works Committee Report of December 20, 1989, S. Report 101–228, that the NO_X emission control technology requirements for cyclone boilers, roof-fired boilers, wet-bottom boilers, stoker boilers and cell burners are to reflect the relative difficulty of controlling NO_X emissions from these boilers. Emission limitations that are promulgated under section 407(b)(2) are to be based on methods that are available for reducing emissions from such boilers that are as cost-effective as the application of low nitrogen oxide burner technology to dry bottom wall-fired and tangentially-fired boilers. House Rep. No. 101–952, 101st Cong., 2d Sess. at 344 (October 26, 1990).

The relevant portion of the Senate Report, which is referenced in the Conference Report, discusses the cost-effectiveness and difficulty of reducing NO_X emissions, explaining that the Senate bill intended:

> To compel utilities to do no more than make most cost-effective reductions. While in past years the Committee has reported legislation that differentiated, and eased, the requirements imposed on cyclone boilers, here the provisions also differentiates [sic], and eases [sic], requirements for wet bottom and stoker boilers as well. This reflects the relative difficulty of controlling NO_X for these technologies.
>
> * * * Also favoring the cost-effectiveness of this section is the development of new, lower-expense technologies. Sorbent injection and decreasing costs for selective catalytic reduction (SCR) may lower the expense of initial NO_X reductions even further. For example SCR has long been viewed as prohibitively expensive, but recent dramatic declines in cost have brought the per-ton-removed price of this technology down to as low as $600, according to recent Electric Power Research Institute metholology followed by EPA. This is comparable to the cost of conventional control methods like low-NO_X burners and thermal de-NO_X However, the provisions in this section are not intended to mandate use of SCR or any other specific technology. Senate Rep. No. 101–228, 101st Cong., 1st Sess. at 332–33 (December 20, 1989).

In short, the legislative history explains that comparability of costs is to be determined by comparing the cost-effectiveness, measured as costs per ton of NO_X removed, of NO_X control technologies on Group 2 boilers with that of low NO_X burner technology on Group 1 boilers. In addition, the Senate Report, which was expressly relied on in the Conference Report, indicates that a control technology (SCR) with a cost-effectiveness of $600 per ton of NO_X removed was regarded as having a cost comparable to that of low NO_X burner technology. At the time the Senate Report was issued, the cost of low NO_X burner technology was thought to be about $150 to $200 per ton of NO_X removed. *Id.* at 470.

In addition to the cost-comparability requirement, section 407(b)(2) requires that, in setting Group 2 emission limitations, the Administrator must ''tak[e] into account available technology, costs and energy and environmental impacts.'' 42 U.S.C. 7651f (b)(2). While consideration of these factors is mandated, Congress did not specify—and thus left to the Administrator's interpretation—how to balance and apply these factors. In particular, the Administrator must decide how to evaluate the factors and what relative weight to give each factor.

D. Methodology for Establishing Group 2 Emission Limitations

In order to meet the requirements of section 407(b)(2), EPA is using the following methodology for establishing Group 2 emission limitations.

First, as detailed in Section III.B, EPA has taken the approach of determining what NO_X control technologies are available for each category of Group 2 boilers and basing Group 2 emission limitations only on such technologies. EPA has considered a combustion control technology available for a Group 2 boiler category only if the technology has been demonstrated on a full-scale boiler in that category. Because post-combustion technology is applied downstream of combustion hardware, a post-combustion technology was considered available for any boiler type if it has been demonstrated on any full-scale boiler.[11] Further, EPA considers only technologies for which there is reliable cost information on which to base a determination of whether they are of comparable cost to LNBs.

Second, as detailed in Section III.E, EPA evaluated each demonstrated control technology and estimated the dollar cost per ton of NO_X removed using the control technology on each boiler in the Group 2 population that is in the appropriate Group 2 boiler category. EPA then compared the dollar cost per ton of NO_X removed for the entire Group 2 population to the dollar cost per ton of NO_X removed for low NO_X burners applied to the entire Group 1 population. In addition, EPA compared the dollar cost per ton of NO_X removed for each Group 2 boiler category (using the appropriate control technology) with the dollar cost of NO_X removed with low NO_X burners on Group 1 boilers. For technical reasons discussed below, EPA chose to adopt a somewhat different cost comparison methodology than the methodology outlined in Appendix B of the March 22, 1994 Acid Rain NO_X regulations (59 FR 13538, 13578 (March 22, 1994)).

Section 407(b)(1) requires the Administrator to set emission limitations for Group 1 boilers (i.e., dry bottom wall-fired and tangentially fired boilers) for Phase I and Phase II based on what emission limitations can be achieved ‘‘using low NO_X burner technology.’’ 42 U.S.C. 7651(b)(1). Only if the Administrator determines that ‘‘more effective low NO_X burner technology is available’’ may the Group 1 emission limitations under section 407(b)(1) be revised for boilers that first become subject to Acid Rain SO_2 and NO_X emission limitations in Phase II. 42 U.S.C. 7651(b)(2).

In short, the NO_X emission limitations set in section 407(b)(1) based on low NO_X burner technology apply to all Group 1 boilers, whether they are first subject to limitations in Phase I or Phase II. Any revisions to these emission limitations must also be based on low NO_X burner technology. EPA concludes that the ‘‘nitrogen oxides controls set pursuant to section 407(b)(1)’’ are low NO_X burner technology applied to all Group 1 boilers. *Id*. EPA therefore believes that section 407(b)(2) requires that the costs of the control technologies used to set emission limitations for Group 2 boilers be comparable to the costs of low NO_X burner technology applied to all Group 1 boilers.

By considering only Group 1, Phase I boilers that have reported low NO_X burner technology cost information, the methodology originally specified in Appendix B eliminates over 90% of the Group 1 boilers from the comparative analysis. This limitation, together with other constraints in the methodology, results in a dataset only marginally adequate for estimating NO_X control costs in a manner consistent with the intent of section 407(b)(2). The population pertinent to the determination, under section 407(b)(2), of Group 1 boiler NO_X control costs is all Group 1 boilers employing or projected to employ low NO_X burner technology[12] to meet the section 407(b)(1) emission limitations. That is the population EPA has used in the proposed rule for establishing emission limitations for Group 2 boilers.

The Appendix B methodology also specifies using the ‘‘average cost-effectiveness (in annualized $/ton NO_X removed) of installed low NO_X burner technology applied to Group 1, Phase I boilers’’ (60 FR 18776) as the basis for identifying comparably cost-effective Group 2 control technologies for the purposes of setting emission limitations for Group 2 boilers. EPA discovered that, for distributions with broad ranges, an analysis based solely on measures of central tendency (e.g., mean, median, mode, or ‘‘average’’) always neglects important information about the spread and shape of the distribution. Based on the actual data that became available in late 1995, EPA has determined that the projected cost-effectiveness of low NO_X burner technology applied to Group 1 boilers, and the projected cost-effectiveness of NO_X control technologies applied to Group 2 boilers are such distributions. The values range from $50/ton to over $1600/ton. Thus, restricting the comparative analysis to the comparison of a single measure of central tendency, such as the average value of the cost-effectiveness of low NO_X burner technology applied to Group 1 boilers, results in a substantial loss of information. Therefore, rather than simply comparing averages, a more illuminating and statistically defensible evaluation would be based on a comparison of ranges of cost-effectiveness and percentages of boilers in each distribution projected to experience similar cost-effectiveness.

EPA has adopted Appendix B when determining the capital cost (in $/kW) of low NO_X burners. However, considering the serious, unanticipated limitations in the Appendix B methodology for estimating and comparing NO_X control cost-effectiveness (in $/ton) for Group 1 and Group 2 boilers, EPA has decided to include all Group 1 boilers in the analysis and to broaden the original concept of ‘‘average’’ to include ranges of cost-effectiveness and percentages of boilers in each population projected to experience similar cost-effectiveness. As a result, EPA proposes to delete Section 3 of Appendix B from part 76 and make limited modifications to the remaining portions of Appendix B consistent with the approach taken in today’s proposal. EPA requests comment on whether it should delete Section 3 of Appendix B from part 76 or follow Appendix B or otherwise modify Appendix B. Further details on the rationale for expanding the original concept of ‘‘averaging’’ to include ranges of cost-effectiveness and percentages of boilers projected to experience similar cost-effectiveness can be seen in the docket item II–A–7, Draft Report, Costs of Low NO_X Burner Technology Applied to Dry Bottom Wall-Fired and Tangentially Fired Boilers, EPA Acid Rain Division, November 30, 1995.

EPA also seeks comment on the proper interpretation of the term ‘‘comparable to the cost’’ as used in section 407(b)(2). Specifically, EPA is seeking comment on the appropriate approach for comparing control technology costs for Group 1 boilers and Group 2 boilers, pursuant to this section of the Act. Such comments should include both the format of the cost which should be addressed (e.g., capital cost, cost per unit of power, cost-effectiveness) and the procedure for

[11] See footnote 9.

[12] Consistent with the Appendix B methodology, boilers employing low NO_X burner technology installed prior to passage of the Act were not considered.

calculating the cost (e.g., data sources, mathematics, unit size constraints etc.).

Based on the above-discussed statutory language and legislative history, EPA maintains that it is reasonable to interpret the cost-comparability provision to require that the distribution of costs per ton of NO_X removed for the Group 2 control technologies be similar, but not necessarily equal, to the distribution of costs per ton of NO_X removed for low NO_X burners as applied to Group 1 boilers.

Third, in Section III.E, EPA estimated the change in electricity rates for consumers resulting from cost (in mills per kilowatt-hour) associated with application of NO_X controls on Group 2 boilers. The Agency maintains that it is reasonable to interpret the required consideration of ''costs and energy * * * impacts'' under section 407(b)(2) to involve the determination of the resulting effect of Group 2 boiler NO_X controls on electricity consumers. 42 U.S.C. 7651f (b)(2). In order to put the energy impact in perspective, EPA determined the average percent change in electricity rates experienced by consumers being served by utilities using Group 2 boilers due to the establishment of emission limitations on Group 2 boilers. This value was then compared to the percent change in nationwide electricity rates due to the establishment of emission limitations for LNBs on Group 1 boilers.

Fourth, in Section III.F, EPA assessed the performance of each cost-comparable Group 2 control technology. The assessment was based on data from industry and government sources on the size of NO_X emission reductions achievable using the control technology on the appropriate type of Group 2 boiler. Based on this data, EPA determined the percentage NO_X emission reduction that is reasonably expected to be achieved.

The expected performance of the control technologies was considered in setting an emission limitation for the relevant boiler type unless EPA determined that, where a technology's performance was expected to be significantly inferior to that of another appropriate technology, the less effective technology was not ''the best system of continuous emission reduction.'' 42 U.S.C. 7651f (b)(2). EPA applied each technology's expected reduction percentage to data on the uncontrolled emissions of each boiler that is in the particular category of Group 2 boilers and that will be subject to the Group 2 emission limitation. It was then determined what percentages of that boiler population will be able to achieve, on an individual boiler basis, a given set of possible NO_X emission limitations. The emission limitation that will be achievable by approximately 90 to 95% of the boiler population was selected as the emission limitation for that category of Group 2 boiler.

EPA chose to base the emission limitation on the emission rate that a target of about 95% of the population will be able to meet. This approach is more relaxed than that used in revising the Group 1 emission limitations because there is less data available on Group 2 boiler NO_X controls. The approach, however, is analogous to the approach used in setting NO_X emission limitations under section 407(b)(1) for Phase I, Group 1 boilers. The same options (averaging and alternative emission limitations) providing compliance flexibility for Phase I, Group 1 boilers unable to meet emission limitations on an individual boiler basis are available for all boilers under today's rule. EPA, however, solicits comment whether the approach being used for setting emission limitations for Group 2 boilers should be consistent with that being used in revising Group 1 emission limitations.

The Agency also assessed the total amount of NO_X emission reductions that may potentially be achieved through use of each available, cost-comparable Group 2 control technology. The change in levels of other pollutants that may result from such reductions were also evaluated. This is a reasonable implementation of the requirement under section 407(b)(2) that the Administrator take account of the environmental impact of Group 2 control technologies.

Finally, after weighing the projected performance and energy and environmental impacts of each available cost-comparable Group 2 control technology, EPA established NO_X emission limitations for Group 2 boiler types based on the appropriate control technologies.

E. Characterization of Costs

1. Low NO_X Burners Applied to Group 1 Boilers

Determination of the cost per ton of NO_X removed for the Phase I low NO_X burners was based on the cost data reported to EPA by 30 Group 1 units [13] (22 wall-fired and 8 tangentially fired boilers). The reported capital costs ($/kW) were analyzed incorporating cost savings due to multiple retrofits at one plant. The resulting cost functions ($/kW vs. MWe) were then levelized and added to estimated annual operating and maintenance costs to arrive at total levelized costs functions (mills/kWh vs. MWe). In arriving at these total costs, the following assumptions were used: (1) a standard capital carrying charge of 11.5%, (2) plant life of 20 years, and (3) a standard operation and maintenance (O&M) cost, including fixed O&M cost of 1.5% [14] of the installed capital cost for annual maintenance and a variable O&M cost accounting for a 0.27% loss in thermal efficiency for retrofit of LNB on wall-fired boilers only. Further, tons of NO_X removed were calculated for each boiler using the correlation between NO_X reduction (percent) and uncontrolled NO_X emission rate (lb/mmBtu). Finally, a cost-effectiveness equation, as a function of uncontrolled NO_X emission rate and capacity factor, was derived for the Group 1 LNBs. Note that all cost functions were computed in 1990 dollars in order to allow comparison of Group 1 and Group 2 control costs using dollars as of the enactment of the Clean Air Act Amendments of 1990. Details of obtaining cost-effectiveness functions for Group 1 LNBs can be found in (see docket items II–A–11, Capital and Annualized Costs of Low NO_X Burner Technology Applied to Phase I, Group 1 Boilers; and II–A–12, Distributions of Cost Effectiveness by Technology) and in EPA's Regulatory Impact Analysis (see docket item II–F–2) of this proposed regulation.

The cost-effectiveness function was then applied to each boiler in the Group 1 population that was above 0.45 lb/mmBtu, for tangentially fired boilers, or above 0.50 lb/mmBtu, for wall-fired boilers, taking into account each boiler's actual usage and uncontrolled NO_X emission rate. Figure 3 shows the distribution of costs that the Group 1 boiler population experiences when applying LNBs.

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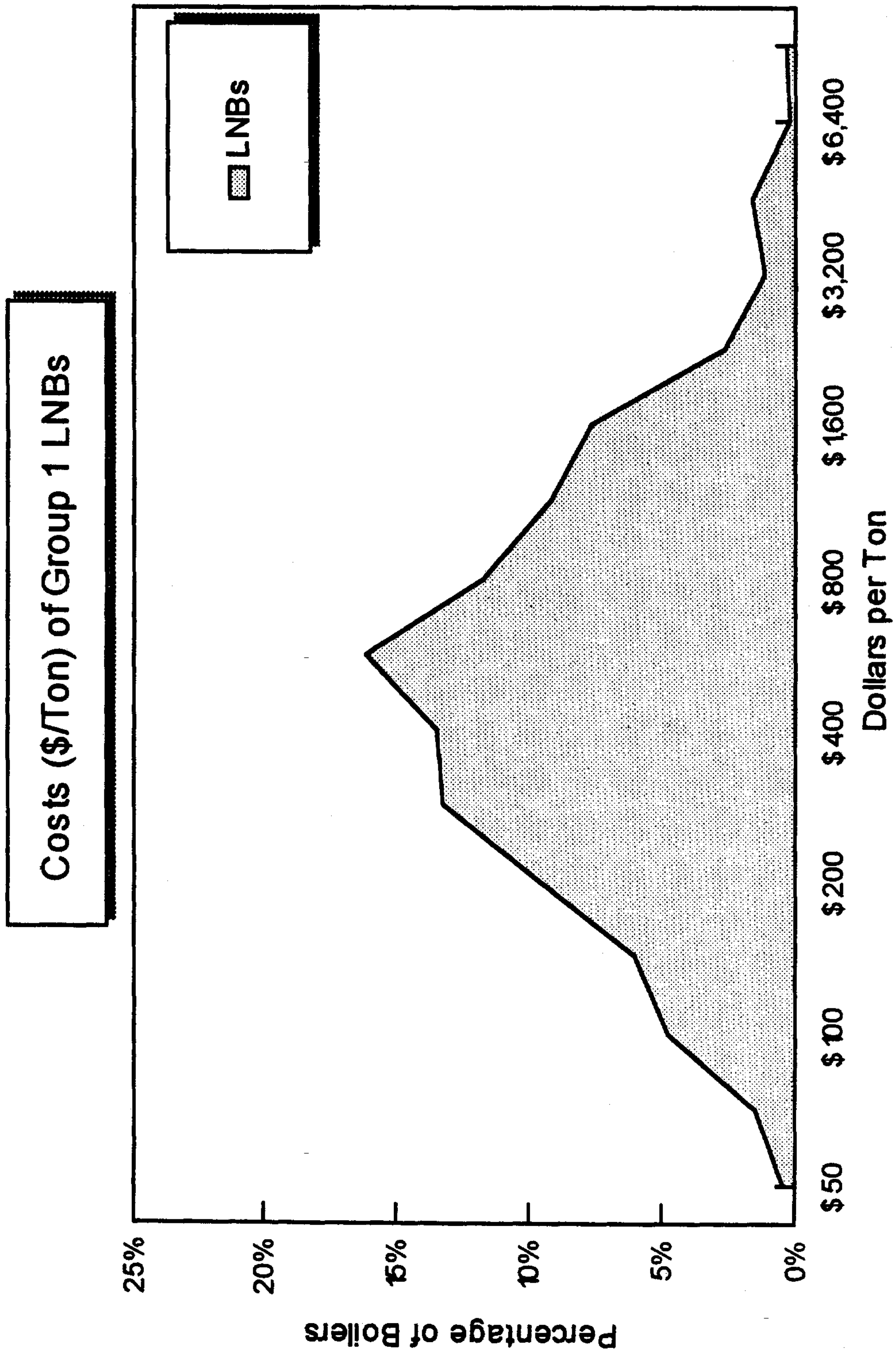
[13] A utility that wishes to submit cost information to augment EPA's analysis should use EPA Form 76B–26, titled NO_X Control Costs for Group 1, Phase I Boilers.

[14] EPA seeks comment on its use of assuming fixed O&M cost of 1.5% or using actual data as reported.

Figure 3



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2. NO_X Controls Applied to Group 2 Boilers

With regard to the cost per ton of NO_X removed for each Group 2 control technology, EPA used the following procedure. Models for Group 2 boiler type/available NO_X control technology combinations were created using information obtained from site visits to Group 2 boilers applying NO_X controls, a major A&E firm's boiler database, commercial applications, and published literature. EPA seeks comment on the accuracy of this data and requests additional data. Using information from the above sources, capital costs were estimated for these models. Subsequently, using the same approach and assumptions used in the levelization of Group 1 LNB costs, cost-effectiveness equations as a function of uncontrolled NO_X emission rate and capacity factor were obtained for each Group 2 boiler type/available NO_X control technology combination. This cost analysis used a modified EPRI class II approach (see docket item II–A–2, Investigation of Performance and Cost of NO_X Controls as Applied to Group 2 Boilers, p. 4–3). The details of estimates of costs of Group 2 boiler NO_X controls can be found in (see docket item II–A–2, Investigation of Performance and Cost of NO_X Controls as Applied to Group 2 Boilers, p. 4–1 to 4–40) and in EPA's RIA (see docket item II–F–2).

The capital costs developed for each technology case reflect costs of retrofitting these technologies under expected site conditions at typical Group 2 boiler installations.[15] The following steps were taken to ensure that the retrofit nature of these costs are properly represented:

- A detailed equipment list was developed for each technology application. This list identified all major new equipment as well as modifications required to the existing plant equipment.
- In developing the various cost estimates, allowances were made for dismantling and removal of unwanted equipment.
- Contingency allowances were provided to cover cost increases associated with uncertain site factors and to cover any unexpected costs associated with retrofitting of large equipment.
- In developing cost estimates for each technology, costs associated with non-standard (i.e., non-essential, or special case) modifications to the existing plant equipment were also accounted for.

As a check, the costs thus developed were also compared and ensured to be consistent with those incurred at existing demonstration or commercial retrofits. It is important to note that retrofits at demonstration projects are not necessarily the easiest possible ones. For example, as noted in docket items II–D–28: Response to questions regarding application of selective catalytic reduction (SCR) to wet-bottom boilers, and to Public Service of New Hampshire's Merrimack 2 unit and II–B–6: Trip Report: visit to Merrimack Unit 2, SCR Retrofit, Merrimack Generating Station, Bow, New Hampshire, June 14, 1995, the SCR application at Merrimack 2 required significant ductwork.

The cost-effectiveness equations for Group 2 boiler/ available NO_X control technology combinations were then applied to each boiler of the appropriate boiler population to arrive at cost-effectiveness distributions for Group 2 boiler NO_X controls. In performing these computations, EPA assumed that only those boilers with NO_X emission rates above the applicable emission limits would install technology. This assumption was made in order to provide a more realistic picture of the cost-effectiveness distributions. The details on the procedure for obtaining cost-effectiveness distributions can be found in EPA's RIA.

3. Comparison of Group 2 Boiler NO_X Control Costs to Low NO_X Burner Costs

As discussed above, in order to determine whether NO_X control technologies as applied to Group 2 boilers are comparable in cost to low NO_X burners as applied to Group 1 boilers, EPA determined the cost-effectiveness of each of the NO_X control technologies applied to each boiler in the respective boiler populations. In determining each boiler/control technology cost-effectiveness distribution, EPA used each boiler's actual usage and uncontrolled NO_X emissions. Additionally, since in today's proposal EPA is exempting cyclone boilers below 80 MWe, the exempted boilers are excluded from the cost effectiveness distributions. Next, the distribution of overall cost-effectiveness for Group 2 boiler NO_X controls was compared to the distribution of overall cost-effectiveness for Group 1 LNBs (see Figure 3). Figure 4 illustrates this comparison.

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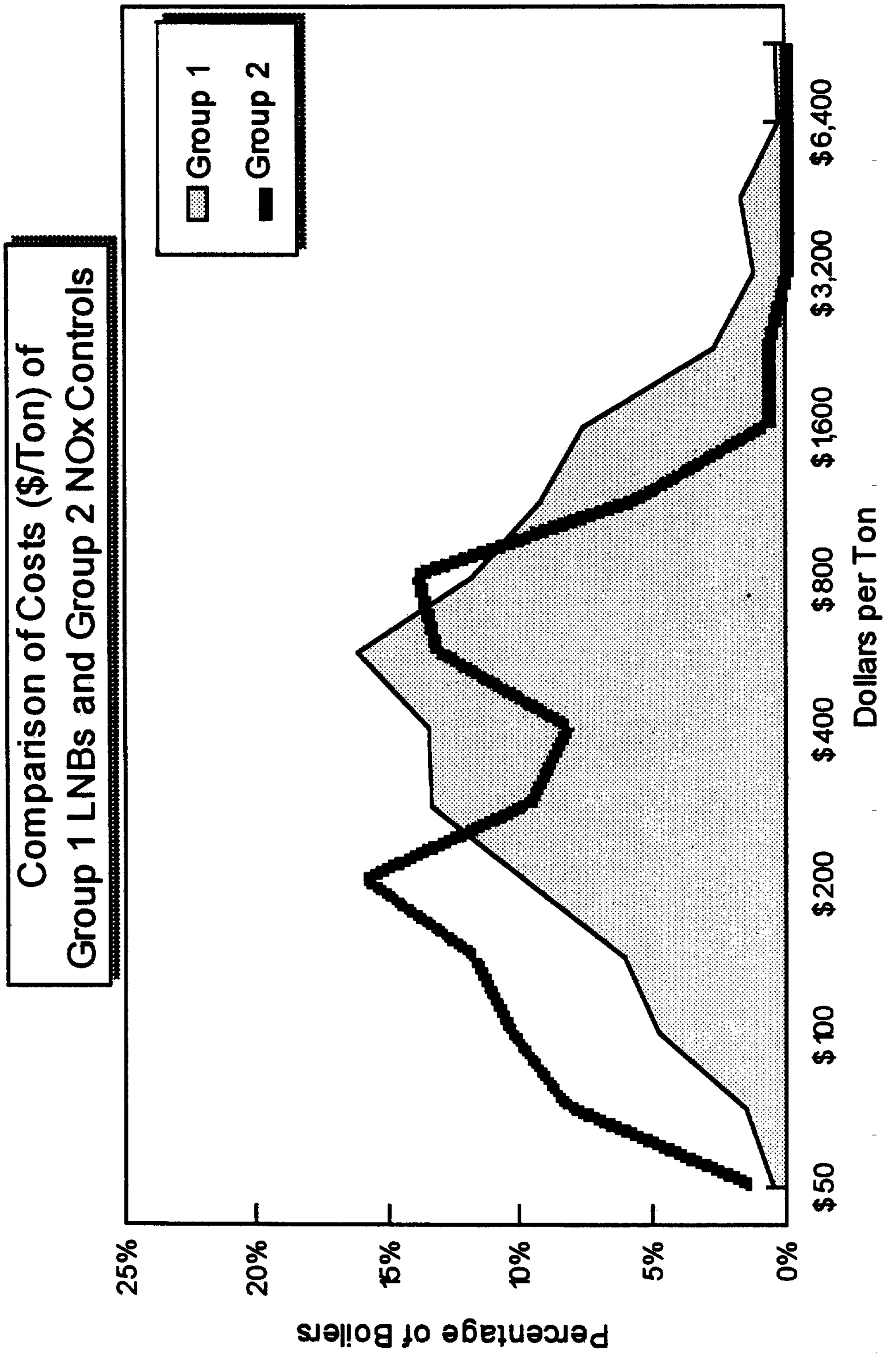
[15] For example, in the SCR analysis EPA assumed a catalyst space velocity equal to 4,900 hr^{-1} for achieving a 50% NO_X reduction.

Figure 4



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The upper and lower 10 percent of each distribution shown in Figure 4 were then excluded in order to compare each distribution without the influence of outliers. EPA determined that the costs for LNBs applied to Group 1 boilers (with outliers removed) ranged from $121/ton to $1,264/ton. The Group 2 NO_X control costs (with outliers removed) ranged from $71/ton to $710/ton. These ranges, tabulated in Table 16, indicate that, excluding outlier, Group 2 boilers applying NO_X controls will experience costs within the range of costs experienced by Group 1 boilers applying LNBs.

Further, EPA determined the range in costs resulting from the application of each available NO_X control technology on each Group 2 boiler type and LNB application on each Group 1 boiler type separately. Subsequently, to provide additional support for cost comparisons, the individual Group 2 boiler/NO_X control technology cost distributions were compared to the Group 1 boilers cost distribution. Table 16 characterizes these cost distributions and the percentage of each Group 2 boiler type population that are expected to experience costs within the range of costs experienced by Group 1 boilers applying LNBs.

TABLE 16.—DISTRIBUTION OF COST-EFFECTIVENESS OF NO_X CONTROLS ($/TON NO_X REMOVED)

Boiler/NO_X control technology	10th percentile	90th percentile	Median	Percent boilers below group 1 90th percentile cost
Group 1/LNBs	121	1264	403	NA
Group 2/NO_X Controls	71	710	207	100
Cell Burners/Plug-ins	57	179	103	100
Cell Burners/Non Plug-ins	75	228	129	100
Cyclones/Coal Reburning	311	897	492	100
Cyclones/Gas Reburning	371	728	555	100
Cyclones/SCR	379	895	574	100
Cyclones/SNCR	426	854	635	100
Wet Bottoms/Combustion Controls	51	148	73	100
Wet Bottoms/SNCR	356	779	458	100
Verticals/Combustion Controls	126	688	196	100
Verticals/SNCR	651	1,400	831	79
FBCs/Combustion Controls	0	0	0	100

With one exception, each Group 2 boiler/NO_X control technology combination experienced costs within the range of costs for Group 1 boilers applying LNBs. After examining the cost comparisons presented in this section, EPA determined that the following Group 2 boiler/NO_X control technology combinations are comparable in cost to Group 1 LNBs:

- Cell burner boilers applying either plug-in or non-plug-in combustion controls.
- Cyclone boilers applying coal reburning, gas reburning, SCR, or SNCR.
- Wet bottom boilers applying combustion controls or SNCR.
- Vertically fired boilers applying combustion controls.
- FBC boilers applying combustion controls.

As discussed below, DOE prepared an independent analysis concerning cyclone boilers, based on different assumptions and data than those used by EPA (see docket item II–D–62, Analysis of Proposed Section 407(b)(2) NO_X Rule, Department of Energy, Staff Paper, December 14, 1995). In this analysis, DOE data for existing applications of LNBs were used to project compliance costs for Group 1 boilers and the results were compared to DOE's projections of cost and performance estimates for SCR and other technologies for controlling NO_X emissions from cyclone boilers. Based on these comparisons, DOE concluded that both cost per unit of electricity generated and cost-effectiveness of controls for cyclone boilers appear to be several times that of LNBs for Group 1 boilers (see docket item II–D–62, Analysis of Proposed Section 407(b)(2) NO_X Rule, Department of Energy, Staff Paper, December 14, 1995). EPA requests comment on this analysis.

In its development of costs for the application of gas reburning on cyclone boilers, EPA used a gas-coal price differential of § 1.23/ mmBtu (1990 dollars). EPA believes that this price differential is similar to recent projections for the year 2010. However, the cost of gas reburning is very sensitive to the gas-coal price differential assumed in the analysis. If a differential of $1.00/mmBtu were assumed, the cost-effectiveness would range from $295 to $588 per ton NO_X removed. Similarly, if a differential of $2.00/mmBtu were assumed, the cost-effectiveness would range from $617 to $1,200 per ton NO_X removed. EPA solicits comment on the gas-coal price differential used in the cost analysis of gas reburning.

Although EPA has not presented gas reburning applied to wet bottom boilers, other than cyclones, in the above analysis, EPA is soliciting comment on whether this NO_X control technology as applied to this boiler type is comparable in cost to low NO_X burner technology and meets the requirements under section 407 (b)(2).

EPA also assessed the energy impacts of Group 2 NO_X controls by determining the average percent change in electricity rates experienced by consumers that are served by utilities operating Group 2 boilers due to the establishment of emission limitations for Group 2 boilers. The energy impact was an estimated 0.35 % increase in electricity rates. EPA then determined the percent change in electricity rates that the same consumers would experience due to the establishment of emission limitations for LNBs on Group 1 boilers. The energy impact due to the Group 1 controls was an estimated 0.36 % increase in electricity rates. Comparing these two values, the energy impacts of Group 2 controls are slightly less than the energy impacts of Group 1 LNBs. (Values were derived assuming an average cost of generating electricity equal to 40 mills/kWh.) This factor was weighed, along with the other factors required to be considered used section 407(b)(2), in deciding what emission limitation to establish for each Group 2 boiler category.

F. Emission Limits for Group 2 Boilers

1. Cell Burner Boilers

Performance of NO_X Controls. Because plug-in and non plug-in NO_X combustion controls, applied to cell-burner boilers, meet the cost-comparability requirement, the performance of these controls is assessed to determine what performance standards are achievable. Table 17 shows various measurements and estimates of the percentage reduction and controlled emission rates for plug-in and non plug-in NO_X controls on cell burner boilers.

TABLE 17.—NO_X REDUCTION PERFORMANCE FOR AVAILABLE NO_X CONTROLS

Source	NO_X control for cell-burner boilers			
	Plug-in		Non plug-in	
	Percent reduction	Controlled emission rate (lb/mmBtu)	Percent reduction	Controlled emission rate (lb/mmBtu)
ETS Data:				
J.M. Stuart #4	52	0.523 [16]		
Muskingum #5	52	0.541 [16]		
Retrofit Applications:				
Muskingum #5 (585 MWe)	>50	0.59 [17]		
Stuart #4 (605 MWe)	>50	<0.58 [17]		
Hatfield's Ferry #2 (555 MWe)	50	0.58 [17]		
Monroe #1 (780 MWe)	44	0.52 [17]		
Sammis #6 (630 MWe)			65 (long term)	0.32–0.47
Four Corners #4 (760 MWe)			40–58 (>70 of MCR [18])	0.49 (MCR)
Brayton Point #3 (500 MWe)			70 (target)	NA
DOE	50	NA	35–70 (LNB + OFA)	NA
EPRI	40–53	NA	NA	NA
UARG	44–50 (short term) 50 (long term)	NA	NA	NA

ETS data shown in the above table suggest that plug-in controls on cell burner boilers can achieve 52% NO_X reduction from full-load, over the long term. Non-plug-in burners, which essentially convert the cell burner boiler to a conventional wall-fired boiler, are expected to reduce NO_X by over 50%, as illustrated in the above table. Boilers that retrofit this NO_X control technology become conventional wall-fired boilers and can therefore emit at NO_X levels below 0.45 lb/mmBtu (see section II). However, EPA has chosen to base the NO_X emission limitations on 50% NO_X reduction. This conservative approach is taken because there are only two boilers for which ETS data are available and because, as shown in the above table, data from all but one of the commercial applications and the bulk of information from industry representatives and DOE suggest that overall, 50% NO_X reduction is attainable by plug-in burners.

As shown in Table 17, the controlled emission rates obtained from ETS are lower than the rates reported in literature for Stuart Unit #4 and Muskingum River Unit #5. This is a result of ETS data being long-term as opposed to short-term full-load data that is the source of the values reported in literature.

Industry commenters were concerned that cell burner boilers retrofit with plug-in burners would have problems sustaining a certain NO_X emission rate over the course of a year. EPA has been informed by the owner/operator of Muskingum River #5 that since the beginning of 1995, the boiler switched to firing low sulfur compliance coal without re-optimizing the coal/air feed system. This caused flame detachment at the burner, thereby increasing the NO_X emissions to ~0.7 lb/mmBtu. EPA believes that once this boiler is re-optimized for the new coal, the NO_X emissions will decrease to previous levels. The owner/operator of Stuart #4 informed EPA that this unit's NO_X emissions increased in the Fall of 1994 and decreased again to original levels after the Winter of 1994. EPA believes this may be a result of coal composition temporarily influencing the NO_X emissions; this condition may therefore be corrected with boiler re-optimization.

Achievable Emission Limit. Applying the projected 50% emission reduction to the uncontrolled emissions of each boiler in the cell-burner population for which NO_X limits are to be set under section 407(b)(2), EPA determined how many of the boilers could achieve various NO_X performance standards. The following table shows the NO_X performance standards levels achievable by between 88.9% and 100% of that cell-burner population.

TABLE 18

NO_X level (lb/mmBtu)	Number of boilers meeting NO_X level	Percent of boilers meeting NO_X level
0.79	35	100
0.73	34	97.1
0.68	33	94.3
0.67	32	91.4
0.65	31	88.6

Table 18 indicates that 94% of the 36 cell burner boilers can achieve a NO_X controlled emission rate of 0.68 lb/mmBtu.

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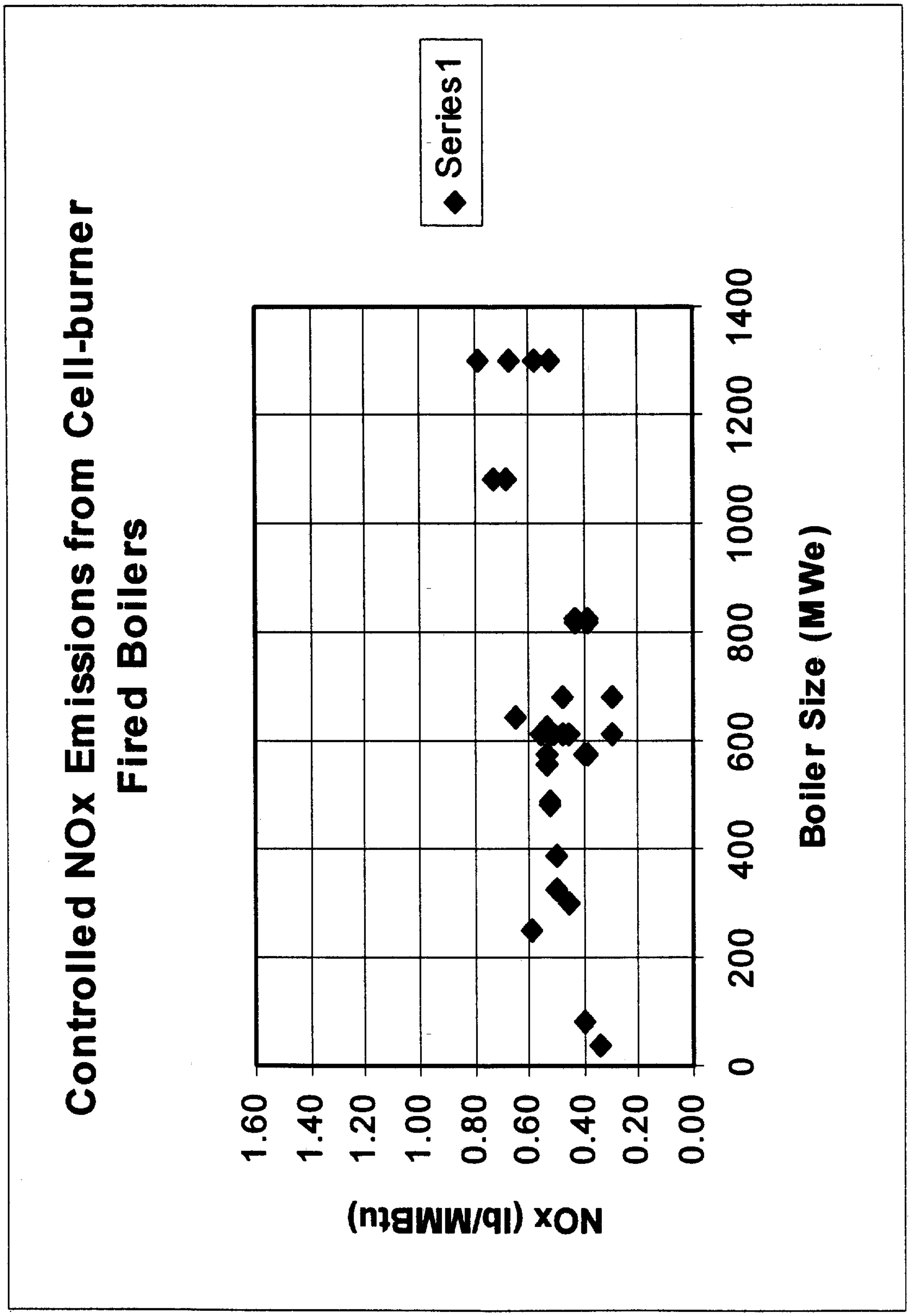
[16] Best 52-day controlled NO_X emission rate, determined per methodology outlined in Section II.

[17] Full load short-term test.

[18] MCR is the maximum continuous rating of a boiler

Figure 5



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Note that the proposed emission limit is greater than the controlled emission rates shown in Table 17. EPA has calculated the uncontrolled emission rates of cell burner boilers to be as high as 1.57 lb/mmBtu and on average 1.02 lb/mmBtu. The boilers shown in Table 17 (JM Stuart #4 at 1.11 lb/mmBtu and Muskingum River #5 at 1.12 lb/mmBtu), though having uncontrolled emissions above the mean emission rate of the cell burner population, are significantly lower than the uncontrolled emission rates of some boilers. Since, as illustrated in Figure 5, the emission limit is based on approximately 95% of the population meeting it, the effect of the higher emitting boilers drives the emission limit towards the high end of the controlled emissions distribution.

Environmental Impacts. According to EPA's Regulatory Impact Analysis, the establishment of 0.68 lb/mmBtu as the emission limit for cell burner boilers will result in a total NO_X emissions reduction of 284,000 tons per year. As shown in the EPA's technical support document, these reductions will be achieved without increases in other air pollutants such as CO or SO_2. In fact, applications to date show a decrease in particulates by as much as 50% as a result of plug-in and non-plug-in retrofits on cell burner boilers.

Additionally, in applications to date, there have been no increases in unburned carbon (UBC) with the application of plug-ins on cell burner boilers. For boilers with non plug-in retrofits, an increase in UBC has been observed. This increase is similar to, or lower than, increases in UBC observed in dry bottom wall-fired boilers retrofitting LNBs. Additionally, the EPA has identified vendors of technology that lowers unburned carbon levels from boilers by optimizing the combustion process (see docket item II–D–15). Further, one vendor provides technology that removes unburned carbon from the flyash (see docket item II–D–13). This process splits the flyash into two parts, one high in carbon and one very low in carbon. The high carbon flyash can be re-combusted in the boiler, while the low carbon flyash can be sold to cement companies. The economic impact of installing such technologies is negligible, compared to the benefits of selling flyash and not needing to dispose of it.

Issues Raised. Applicable Emission Limit. EPA investigated whether boiler operating conditions after January 1, 1995 affected the controlled NO_X emission rate, using CEM measured data submitted to EPA's Emissions Tracking System (ETS). To date, no substantial differences between NO_X emission rates before and after January 1, 1995, have been observed. EPA believes that the utilities can receive NO_X emission guarantees for various coal types from manufacturers of NO_X control equipment. The manufacturers of control equipment appear to design for a certain controlled NO_X emission rate taking into account various coal types.

Increased Boiler Corrosion. EPA also investigated whether the application of combustion NO_X controls on cell burner boilers would cause corrosion or erosion of furnace walls. These impacts could affect costs associated with such retrofits. However, major vendors of plug-in and non plug-in combustion controls on cell burners (Babcock & Wilcox and Riley Stoker), as well as utilities, have not found significant corrosion and erosion problems associated with applications of this technology to date.

Conclusions. For the following reasons, EPA concludes that 0.68 lb/mmBtu is a reasonable emission limitation that meets the requirements of section 407(b)(2). First, plug-in burners applied to cell burner boilers are an available control technology that meets the cost-comparability requirement. Second, a second available control technology, non plug-in retrofits, also meets the cost-comparability requirement. This technology can be applied to 3-cell configurations if plug-ins are not effective. Because it is capable of greater NO_X reduction efficiency than plug-ins, it can meet the 0.68 lb/mmBtu emission limit. Third, an emission limit of 0.68 lb/mmBtu is achievable in that it can be met by 94% of the cell burner population with the application of plug-in or non plug-in burners at a 50% NO_X removal efficiency. ETS data for two cell-burner boilers that have already installed such controls were at or below this limit 94% of the time they were operated. Fourth, as shown in section III.E, the energy impact, i.e. the cost impact on electricity consumers, of using the available control technologies to meet the recommended emission limit is small and similar in magnitude to the energy impact of using LNBs on Group 1 boilers. Finally, the recommended emission limit results in a reduction of NO_X emissions by approximately 284,000 tons per year (see Regulatory Impact Analysis, docket item II–F–2) without increases in CO, CO_2, SO_2, or solid waste and with potentially a 50% decrease in particulates. As discussed in section II.D, there are substantial human health and environmental benefits associated with the additional NO_X reductions and meeting the proposed emission limitation is a cost-effective means of achieving such reductions.

2. Cyclone Boilers

Performance of NO_X Controls. Four NO_X control technologies that are available for application to cyclone boilers meet the cost comparability requirement: (1) Coal reburning, (2) gas reburning, (3) SCR, and (4) SNCR. Since EPA must base the emission limitation on the ''best system of continuous emission reduction'' per section 407(b)(1), and as shown in the Technical Support Document, the expected NO_X removal capability of SNCR is approximately 35%, lower than the percent reduction of the other technologies available for cyclone boilers, EPA is not considering SNCR in establishing the emission limitation for cyclone boilers.

Table 19 shows measurements and various estimates of the percent reduction and controlled emission rates for coal reburning, gas reburning, and SCR on cyclone boilers. EPA also believes that combustion control and combustion optimization approaches may also achieve cost-effective, significant NO_X reductions. However, these control approaches have not yet been thoroughly investigated by the utility community.

TABLE 19.—NO_X REDUCTION PERFORMANCE FOR AVAILABLE NO_X CONTROLS

Source	NO_X Control for cyclone boilers					
	Coal reburning		SCR		Gas reburning	
	Percent reduction	Controlled emission rate (lb/mmBtu)	Percent reduction	Controlled emission rate (lb/mmBtu)	Percent reduction	Controlled emission rate (lb/mmBtu)
Retrofit Applications:						
Nelson Dewey 2 (110 MWe).	52.4–55.4 (MCR)	0.34–0.39				
Merrimack 2 (320 MWe).			65 (target)	NA		
Niles 1 (108 MWe).					50 (long term)	0.58–0.67 (approx.)
Lakeside 7 (33 MWe).					66 (long term)	0.344
DOE	40–60 [19]	NA	80–90	NA	55–65	NA
EPRI (based on retrofits).	50–55 (MCR)	NA	65 (MCR, target)	NA	50–60 (MCR)	NA
UARG (based on retrofits).	55–60 (MCR), 33–50 (loads down to 35% MCR).	NA	65 (target)	NA	40 (long term, >75% MCR), 47% (MCR).52–77 (short term, >70% MCR).	NA

EPA believes that 50% NO_X reduction from full-load values can be achieved by coal reburning and SCR [20] controls over the long term. This represents the average of the range in performance expected by DOE. A 50% NO_X reduction is also on the conservative end of the performance range achieved over the long term at the only demonstration project, and is on the lower end of performance projections by utility groups.

Gas reburning is expected to reduce NO_X emissions by 60%. This value is about the average of the range of performance at the two existing gas reburning projects and the overall range of DOE and EPRI performance estimates. The lower reduction percentages suggested by UARG reflect boiler operation at lower than full loads.

Some industry commenters have expressed concerns that applications of coal or gas reburning on some cyclone boilers may not achieve 50% or 60% NO_X reductions, respectively. EPA solicits comment from vendors and utilities on the performance of these NO_X control technologies.

Additionally, information recently obtained by EPA from a utility that attempted to optimize the combustion process in cyclone boilers, shows that reductions in the order of 10%–20% can be achieved by optimizing fuel and air flows to cyclones. EPA solicits comment from vendors and utilities on the applicability of combustion modification and optimization techniques that lower NO_X emissions from cyclone boilers.

Achievable Emission Limit. For the purposes of applying a NO_X emission limitation to cyclone boilers, EPA chose 50%, a conservative reduction percentage considering the performance level of the three qualifying technologies. Applying the projected 50% emission reduction to the uncontrolled emissions of each boiler over 80 MWe in the cyclone population for which NO_X limits are to be set under section 407(b)(2), EPA determined how many of the boilers could achieve various NO_X emission levels. The following table shows the NO_X emission levels achievable by between 89.3% and 100% of the cyclone boiler population.

TABLE 20

NO_X level (lb/mmBtu)	Number of boilers meeting NO_X level	Percent of boilers meeting NO_X level
0.98	75	100
0.97	73	97.3
0.94	70	93.3
0.86	68	90.7
0.85	67	89.3

Table 20 indicates that 93% of the 75 cyclone boilers can achieve a NO_X controlled emissions rate of 0.94 lb/mmBtu.

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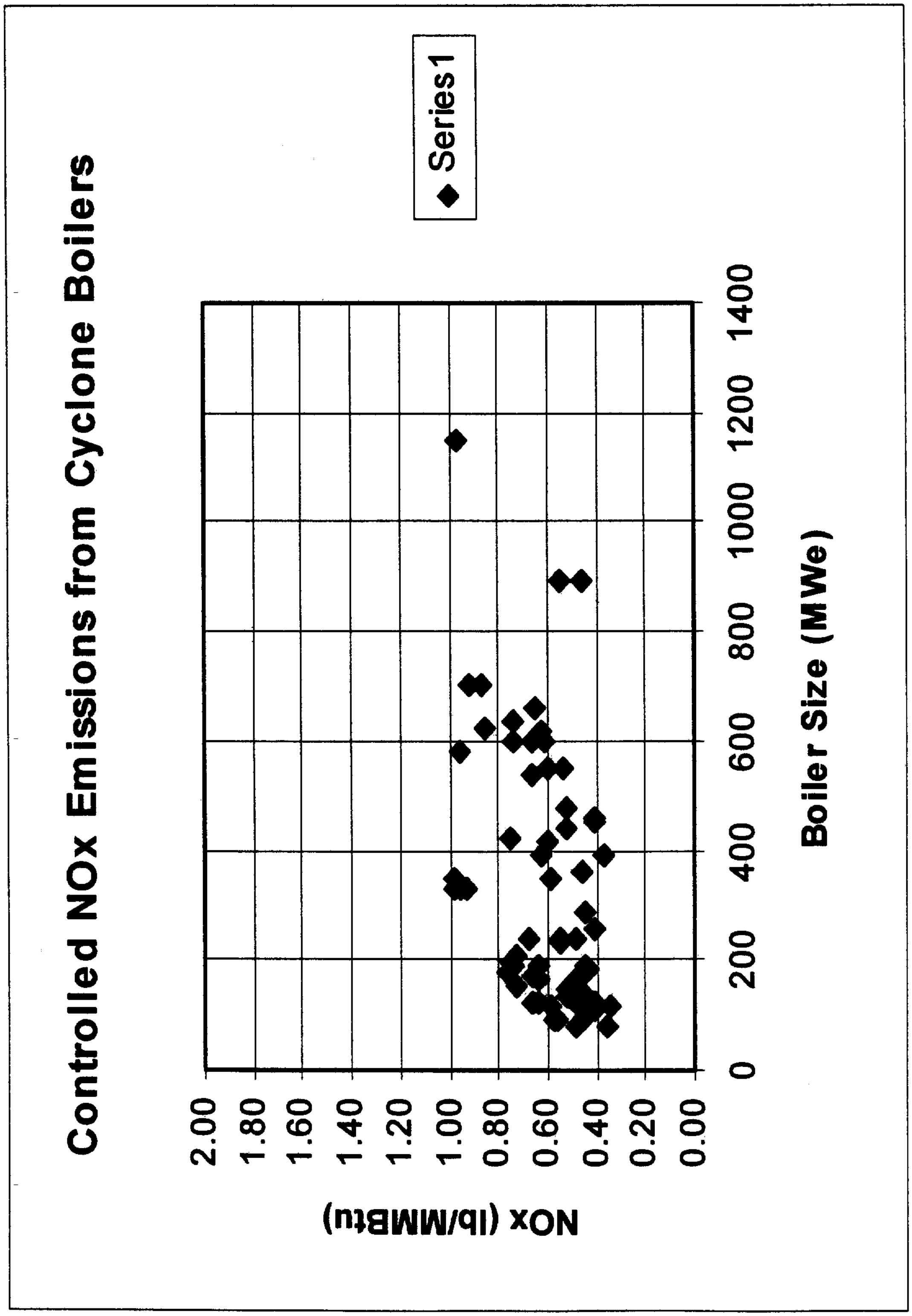
[19] This range reflects use of different coal types, specifically at Nelson Dewey 2, 55.4% NO_X reduction at 110 MWe using subbituminous coal and 35.8% NO_X reduction at 60 MWe using bituminous coal.

Figure 6



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Note that the proposed emission limit is greater than the controlled emission rates shown in Table 19. The boilers shown in Table 19 have uncontrolled emissions significantly lower than the uncontrolled emission rates of some boilers. Since, as illustrated in Figure 6, the emission limit is based on approximately 95% of the population meeting it, the effect of the higher emitting boilers drives the emission limit towards the high end of the controlled emissions distribution.

Environmental Impacts. According to EPA's Regulatory Impact Analysis, the establishment of 0.94 lb/mmBtu as the emission limitation for cyclone boilers will result in additional NO_X emissions reductions of approximately 167,000 tons per year. These reductions are achieved with little or no increases in other air pollutants or solid waste. In fact, when applying gas reburning, significant SO_2 and CO_2 emission reductions are also achieved.

Issues Raised. Applicability of Reburning. Some concern has been expressed regarding the ability of some cyclone boilers to retrofit gas or coal reburning; of particular concern are smaller boilers. EPA investigated whether the retrofit of both coal and gas reburning may be infeasible for some small boilers. According to Babcock & Wilcox, the only vendor for both cyclone boilers and coal reburning, many boilers less than 80 MWe may not be able to effectively retrofit reburning. Since there appears to be great concern regarding the reburning retrofitability of small boilers and since their combined NO_X emissions (in tons) account for only about 10,000 tons out of about 1.8 million tons of total annual uncontrolled NO_X emissions from units with Group 2 boilers, today's proposal exempts cyclones less than 80 MWe from this rulemaking.

EPA is also asked to exempt large cyclone boilers due to uncertainties concerning the ''scaling up'' of reburning technology from small to large boilers. Some utilities are concerned that since large boilers have greater furnace volumes, the reburning fuel will not be able to mix adequately with the flue gas and therefore, the NO_X reduction will be significantly less than the expected 50%.

The feasibility of reburning on any boiler depends on the following requirements: (1) The availability of adequate residence time in the reburn and burnout zones; (2) the mixing of reburn fuel and overfire air; and (3) the ability to achieve penetration of reburn fuel into combustion gas across the distances associated with large units.

It has been shown in a survey (see docket item II–I–22, Final Report, Demonstration of Coal Reburning for Cyclone Boiler NO_X Control, prepared by Babcock and Wilcox for the Department of Energy, DOE/PC/89659–T16, February 1994, pp. 2–7 and 2–8) that majority of the boilers had the requisite residence time available for coal reburning. Further, gas reburning applications require less residence times than corresponding coal reburning applications. Thus, in general, most of the cyclones have adequate residence times available for applications of either coal or gas reburning. However, natural gas may not be available at all cyclone boiler locations. EPA solicits comment on what cyclone boilers do not have access to natural gas.

Combustion gas flow patterns in relatively larger boilers are expected to be less complex than those found in smaller units. Thus general mixing of reburn fuel and combustion gas would be expected to be better in larger boilers.

Penetration of reburn fuel into combustion gas does depend on the distance between the front and rear walls of a boiler. However, with proper design of reburn fuel burners/injectors, the requisite penetration can be achieved.

Additionally, EPA believes that though all reburn demonstrations in the U.S. have been on relatively small boilers (about 100 MWe), a 300 MWe boiler in the Ukraine has been successfully retrofitted and operated with gas reburn by a large U.S. manufacturer and is achieving 50% of NO_X reduction over the load range. Since no retrofit of reburning to date (including this 300 MWe boiler) has shown a long-term NO_X reduction lower than 50% from full-load values and NO_X emissions from large cyclone boilers are clearly not *de minimis,* EPA adopts 50% as the minimum removal capability of reburning. EPA also notes that SCR is available as an alternative NO_X control technology for cyclone boilers.

Applicability of Reburning at Low Loads. EPA has investigated the concern about the application of reburning at reduced boiler loads because this could affect slagging and NO_X reduction efficiency in the cyclone.

Utility representatives project that reburning will be inoperable at low boiler loads (less than 40% of full load) (see docket item II–E–10). EPA has investigated the actual hourly loads of 22 Phase I cyclone boilers and found that, collectively, they were at less than 40% of full load only 5% of the time in 1994. Further, the retrofit of coal reburning to Nelson Dewey Unit 2 achieved long-term NO_X reductions greater than 50% even though the reburning was stopped during periods when the cyclone was operating at loads lower than 40% of full load.

According to the manufacturer (see docket item II–I–90, Babcock & Wilcox, Steam: Its Generation and Use), individual cyclone furnaces cannot be operated below half load without causing freezing of slag. On smaller cyclone boilers, equipped with only a few cyclone furnaces, load reduction is achieved by turning down each of the individual furnaces. On these boilers, typical minimum operational load, in the absence of reburning, would be about 50 percent of the rated boiler capacity. With reburning providing 15–20 percent of total heat input, the minimum operational load for some small boilers could be about 58–60 percent of rated capacity. However, the situation is different for relatively larger cyclone boilers. Typically, these boilers are equipped with many cyclone furnaces. Load reduction on these cyclone boilers is achieved by removing individual cyclone furnaces from service. Depending on the number of individual cyclone furnaces taken out of service and the level of load reduction on each of the remaining furnaces, such a boiler could be operated over a wide range of loads. Hence, based on the proposed 80 MWe size cut-off, application of reburning on cyclone boilers should not be restricted by load considerations. Further, for those few units where load considerations restrict use of reburning, SCR is available as a cost effective NO_X control measure.

It is worth noting that gas reburning has been applied successfully at a small cyclone boiler (Lakeside Unit 7, 33 MWe). Long term NO_X reduction at this unit has been reported to be over 65 percent.

Applicability of Combustion Controls on Cyclone Boilers. EPA has identified two U.S. manufacturers that have combustion control approaches to controlling NO_X from cyclone boilers, and the performance and cost of such approaches appear to be very promising. Although these staged combustion systems appear promising, they have not yet been demonstrated. In addition, cyclones may be able to be ''optimized'' for NO_X emission reduction without the addition of controls. A major utility has done such work in the past achieving 10–20% reductions by changing the air/fuel ratios. The same utility also intends to examine combustion modification controls. Modeling will be completed this year, and demonstration projects will be underway in 1996. Combined with emission reductions from fuel changes, total emission reductions of 20 to 40% from 1990 baseline levels are anticipated. EPA calculates that if cyclone owners successfully apply combustion optimization techniques, more than 50% of the affected units would meet the 0.94 lb/mmBtu emission limit at dramatically reduced costs. EPA is not basing its proposed emission limitation for cyclone boilers on combustion optimization because there is currently inadequate information to conclude that it is an available technology under section 407 (b)(2) for cyclone boilers.

Cost Comparability of Available Cyclone Boiler NO_X Controls. EPA recognizes that some industry commenters believe that the available NO_X control technologies for cyclone boilers are not comparable in cost, on a dollars per ton of NO_X removed basis, to low NO_X burners applied to Group 1 boilers. Although EPA is proposing that there are NO_X control technologies available for cyclone boilers that are comparable in cost to low NO_X burners applied to Group 1 boilers, the Agency stresses that it will welcome, and fully consider in the final rule, any additional data or other information relevant to the issue of cost comparability. For the same reasons (discussed above) that EPA is not delaying the proposed revised limitations for Phase II, Group 1 units, EPA is today proposing emission limitations for cyclone and other Group 2 boilers, based on what it believes is a sufficient record. An analysis by DOE, based on different assumptions and data than those used by EPA and including information which has not been verified by EPA, concludes that the average cost-effectiveness of LNB technology for Group 1 boilers is $260 per ton, and that the corresponding cost effectiveness for SCR applied to cyclone boilers is $830 per ton [21] (see docket item II–D–62, Analysis of Proposed Section 407(b)(2) NO_X Rule, Department of Energy, Staff Paper, December 14, 1995. pp. 2–12). If EPA determines that this analysis is appropriate and this degree of difference is deemed to not be ''comparable'' for purposes of setting a Group 2 standard, and if coal or gas reburning also do not meet the cost comparability requirements, then no standard would be promulgated for cyclone boilers, unless more cost-effective control technology is identified during the comment period for this rule.

EPA is specifically requesting comment on the adequacy of the data as to its accuracy and completeness to (1) support an emission limitation of 0.94 lb/mmBtu for cyclone boilers or (2) to support not establishing an emission limit for cyclone boilers at this time. EPA requests (a) data and analysis on the cost and performance of Group 1 low-NO_X burner control technologies and (b) cost and performance data for demonstrated NO_X control technologies for cyclone boilers including but not limited to coal reburn, gas reburn, SCR, SNCR or other NO_X control technologies. EPA also seeks information which might suggest a size cutoff or groupings for cyclone boilers to be controlled by each of these technologies and analysis supporting this recommendation. As noted below, EPA's view of available information indicates that technology to reduce NO_X emissions from cyclone boilers is comparable to the cost of low NO_X burners for Group 1 boilers. However, analysis provided by DOE, based on different assumptions and data, indicates that the cost of control technology for cyclone boilers is several times higher than the cost of LNB for Group 1 boilers (see docket item II–D–62, Analysis of Proposed Section 407(b)(2) NO_X Rule, Department of Energy, Staff Paper, December 14, 1995.). EPA also requests comments and recommendations on these two analytical approaches.

Conclusions. For the following reasons, EPA concludes that 0.94 lb/mmBtu is a reasonable emission limitation that meets the requirements of section 407(b)(2). First, coal reburning, gas reburning and SCR applied to cyclone boilers are available technologies that meet the cost-comparability requirement. Second, the proposed emission limit of 0.94 lb/mmBtu is an achievable emission level that 93% of the cyclone boiler population will be able to meet with the application of coal reburning, gas reburning, or SCR. Third, as shown in section III.E, the cost impact on electricity consumers of using these control technologies to meet recommended emission limit is small and similar in magnitude to the energy impact of using LNBs on Group 1 boilers. Finally, the recommended emission limit results in a reduction of NO_X emissions by approximately 167,000 tons per year with little or no increases in other air pollutants or solid waste disposal. As discussed in section II.D, there are substantial human health and environmental benefits associated with the additional NO_X reductions and meeting the proposed emission limitation is a cost-effective means of achieving such reductions.

3. Wet Bottom Boilers

Performance. Because combustion NO_X controls meet the cost-comparability requirement, the performance of these controls is assessed to determine what performance standards are achievable. Though SNCR also meets the comparability criteria, at a typical 35% NO_X reduction it is not the ''best system of continuous emission reduction'' per section 407(b)(2) available for wet bottom boilers, and as such, is not considered when setting emission limits for wet bottom boilers.

Combustion controls have not yet been applied to wet bottom boilers in the U.S. However, a major utility has announced plans to retrofit a wet bottom wall-fired boiler in the fall of 1995 with combustion controls, specifically a two-level overfire air (OFA) system. According to the utility's engineering estimates, the two-level OFA system will achieve an overall 50% reduction from uncontrolled levels and will allow the wet bottom boiler to have a NO_X emission rate of 0.71 lb/mmBtu (see docket items II–D–30: J.M. McManus, American Electric Power Service Corporation, to L. Kertcher, EPA: Acid Rain Division, May 26, 1995, Enclosing information relating to Kyger Creek Unit 5 low NO_X System Design; II–B–7: Trip Report: visit to Kyger Creek Unit 5 Low NO_X Combustion Modification Retrofit; and II–A–2: Investigation of Performance and Cost of NO_X Controls as Applied to Group 2 Boilers at p. 3–18 & 3–19).

Based on the above project's projected performance, EPA projects that combustion controls applied to wet bottom boilers can achieve a 50% reduction of NO_X emissions from uncontrolled levels. EPA notes the control technology on which it is based, OFA, has been widely used in the electric utility industry as a NO_X control technology for other types of boilers for many years (57 FR 55640).

Achievable Emission Limit. Applying the projected 50% emission reduction to the uncontrolled NO_X emissions of each boiler in the wet-bottom burner population for which NO_X limits are to be set under section 407(b)(2), EPA determined how many of the boilers could achieve various NO_X performance standards. The following table shows the NO_X performance standards achievable by between 89.7% and 100% of the wet bottom boiler population.

[20] Of the three technologies, SCR allows the user to design for various levels of performance ranging as high as 90% NO_X reduction. However, increases in performance are directly proportional to increases in cost. For the purposes of this rule, and to more accurately compare SCR with coal and gas reburning, the NO_X reduction performance of SCR is set at 50%.

TABLE 21

NO_X level (lb/mmBtu)	Number of boilers meeting NO_X level	Percent boilers meeting NO_X level
0.95	38	100
0.86	37	97.4
0.84	34	89.5

Table 21 indicates that 97% of the 39 wet bottom boilers can achieve a controlled NO_X emission rate of 0.86 lb/mmBtu.

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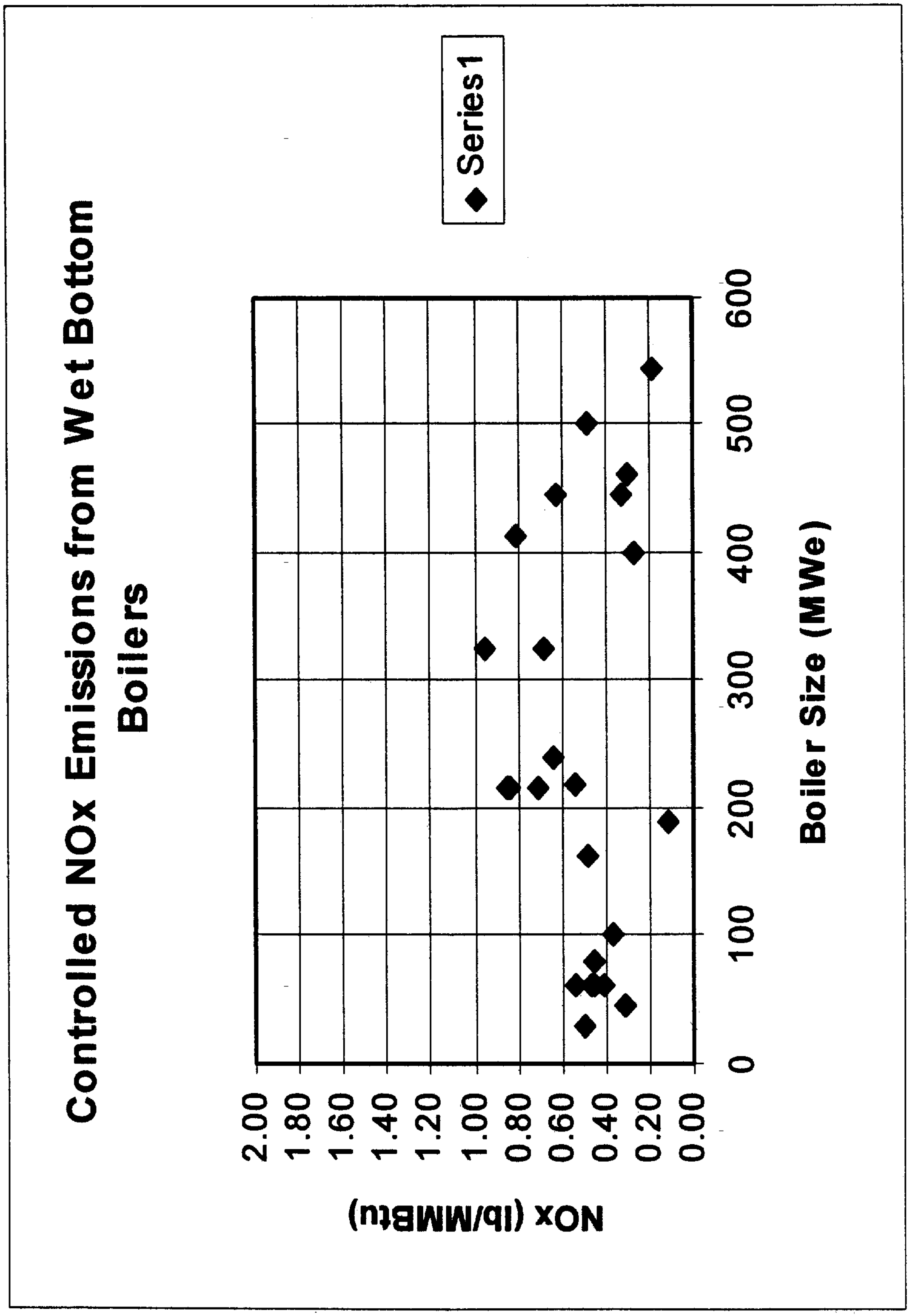
Figure 7



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Note that the proposed emission limit is greater than the controlled emission rate expected from Kyger Creek #5 (0.71 lb/mmBtu). EPA has calculated the uncontrolled emission rates of wet bottom boilers to be as high as 1.90 lb/mmBtu and on average 1.12 lb/mmBtu. Kyger Creek #5 (at 1.41 lb/mmBtu), though having uncontrolled emissions above the mean emission rate of the wet bottom boiler population, is lower than the uncontrolled emission rates of some boilers. Since, as illustrated in Figure 7, the emission limit is based on approximately 95% of the population meeting it, the effect of the higher emitting boilers drives the emission limit towards the high end of the controlled emissions distribution.

Environmental Impacts. According to the EPA's Regulatory Impact Analysis, the establishment of 0.86 lb/mmBtu as the emission limit for wet bottom boilers will result in a total NO_X emissions reduction of approximately 112,000 tons per year. These reductions will be achieved through the use of OFA, a form of combustion NO_X control technology. Since LNBs are also a form of combustion control technology, EPA expects the environmental and solid waste impacts of OFA on wet bottom boilers to be similar to the impacts of LNBs or OFA Group 1 boilers. The application of LNBs or OFA on Group 1 boilers does not increase levels of CO, SO_2, or CO_2 but may increase the unburned carbon (UBC) level in the flyash. For boilers that do experience increases in UBC from uncontrolled levels, technologies that lower UBC to below uncontrolled levels at very little or no cost are available (see section IV.D.1).

Conclusions. For the following reasons, EPA concludes that 0.86 lb/mmBtu is a reasonable emission limitation that meets the requirements of section 407(b)(2). First, combustion NO_X controls applied to wet bottom boilers are an available technology that meets the cost-comparability requirements. Second, an emission limit of 0.86 lb/mmBtu is a level that 97.4% of wet bottom boiler population should be able to meet with the application of combustion controls at 50% NO_X removal efficiency. Third, as shown in section III.E, the cost impact on electricity consumers of using this control technology to meet the recommended emission limit is small and similar in magnitude to the energy impact of using LNBs on Group 1 boilers. Finally, the recommended emission limit results in a reduction of NO_X emissions by approximately 112,000 tons per year without significant increases in CO, CO_2, SO_2, or solid waste disposal. As discussed in section II.D, there are substantial human health and environmental benefits associated with the additional NO_X reductions and meeting the proposed emission limitation is a cost-effective means of achieving such reductions.

We note that earlier in the preamble we requested comment on whether gas reburning as applied to wet bottom boilers is comparable in cost to low NO_X burner technology and meets the requirements of Section 407(b)(2). Commenters believing that gas reburning meets the necessary requirements should also comment on what percent reduction is achievable and what effect, if any, there would be on the emission limit set for wet bottom boilers.

4. Vertically Fired Boilers

Performance. Because the combustion controls applied to vertically fired boilers meet the cost comparability requirements, the performance of these controls is assessed to determine what performance standards are achievable. Table 22 shows various measurements of the percent reduction and controlled emission rates for combustion controls on vertically fired boilers (see docket items II–A–2 at p. 3–18 & 3–19, II–B–4, and II–B–5).

TABLE 22.—NO_X REDUCTION PERFORMANCE FOR AVAILABLE NO_X CONTROLS

Source	NO_X control for vertically fired boilers — Combustion controls: Percent reduction	NO_X control for vertically fired boilers — Combustion controls: Controlled emission rate
AEP Tanner's Creek 1 (152 MWe).	40 (estimated)	0.57 (estimated)
Duquesne Light Elrama Unit 1 (100 MWe).	42	0.45
Duquesne Light Elrama Unit 2 (100 MWe).	≥40	~0.45
Duquesne Light Elrama Unit 3 (125 MWe).	≥40	~0.45

Based on the above NO_X reduction performance, EPA is projecting a 40% percentage reduction in NO_X emissions using combustion controls on vertically fired boilers. Every project in Table 22 achieved or is expected to achieve 40% or higher NO_X reductions. These projects achieve NO_X reductions by using two different combustion air staging systems: one that redistributes the combustion air within the burners and the second that accomplishes redistribution through OFA ports. EPA notes that this approach to controlling NO_X has been used by many vendors of technology and utilities for many years to control NO_X emissions from other types of boilers, e.g., dry bottom wall-fired and tangentially fired boilers (57 FR 55640).

Achievable Emission Limit. Applying the projected 40% emission reduction to the uncontrolled emissions of each boiler in the vertically fired population for which NO_X limits are to be set under section 407(b)(2), EPA determined how many of the boilers could achieve various NO_X performance standards. The following table shows the NO_X performance standards achievable by between 84.8% and 100% of the vertically fired boiler population.

TABLE 23

NO_X level (lb/mmBtu)	Number of boilers meeting NO_X level	Percent of boilers meeting NO_X level
0.85	29	100
0.80	28	96.6
0.74	26	89.7
0.72	24	82.8

Table 23 indicates that 97% of the 33 vertically fired boilers can achieve a NO_X controlled emissions rate of 0.80 lb/mmBtu

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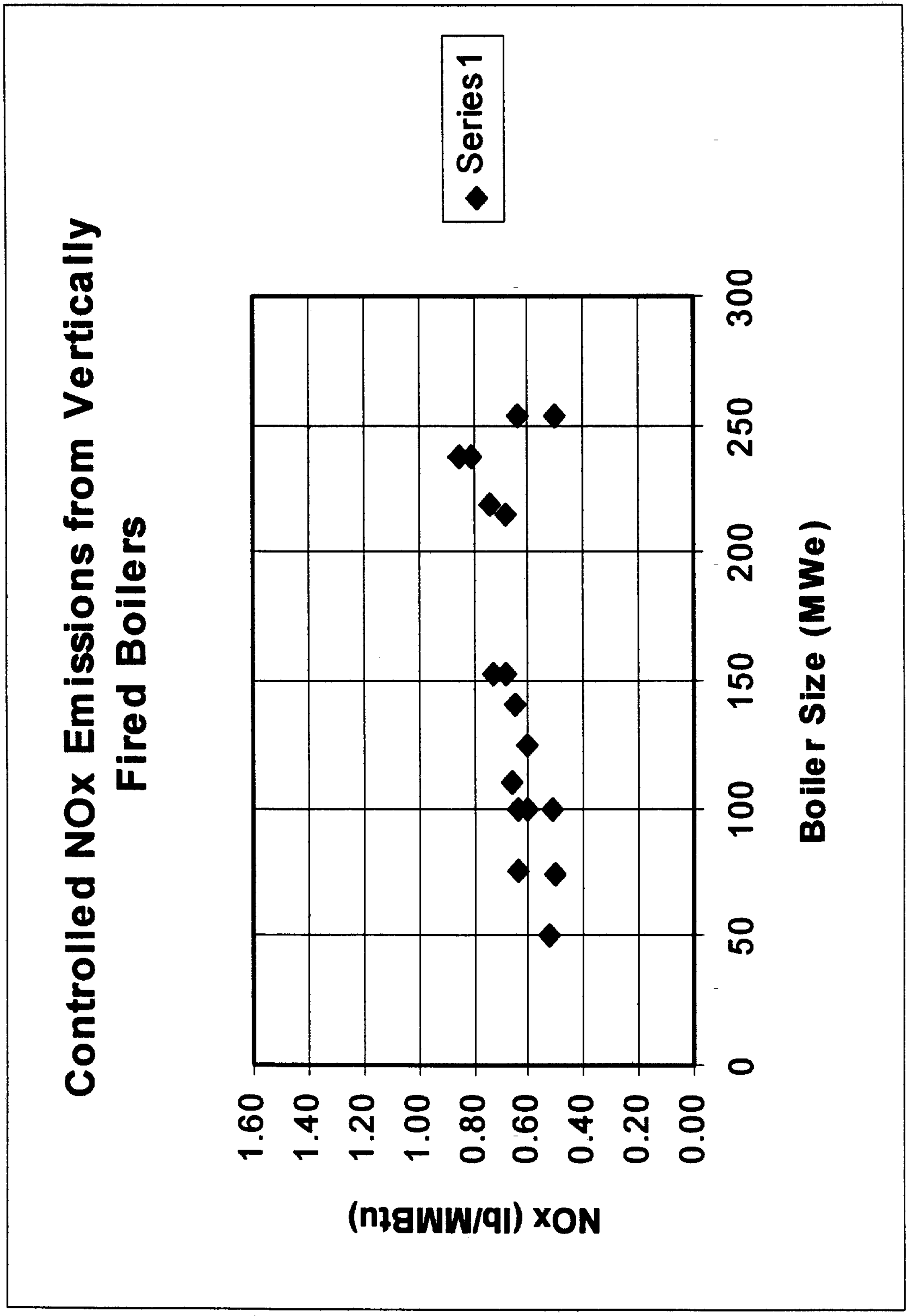
Figure 8



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Note that the proposed emission limit is greater than the controlled emission rates shown in Table 22. EPA has calculated the uncontrolled emission rates of vertically fired boilers to be as high as 1.42 lb/mmBtu and on average 1.06 lb/mmBtu. The boilers shown in Table 22 have uncontrolled emissions below the mean emission rate of the vertically fired population and, thus, are significantly lower than the uncontrolled emission rates of more than half of the boilers. Since as illustrated in Figure 8, the emission limit is based on approximately 95% of the population meeting it, the effect of the higher emitting boilers drives the emission limit toward the high end of the controlled emissions distribution.

Environmental Impacts. According to the EPA's Regulatory Impact Analysis, the establishment of 0.80 lb/mmBtu as the emission limit for vertically fired boilers will result in a total NO_X emissions reduction of approximately 57,000 tons per year. These reductions will be achieved through the use of combustion NO_X control technology. Since LNBs are also a form of combustion control technology, EPA estimates that the environmental and solid waste impacts of combustion controls on vertically fired boilers will be similar to the impacts of LNBs or OFA on Group 1 boilers. The application of LNBs or OFA on Group 1 boilers does not increase levels of CO, SO_2, or CO_2 but may increase the unburned carbon (UBC) level in the flyash. For boilers that do experience increases in UBC from uncontrolled levels, technologies that lower UBC to below uncontrolled levels at very little or no cost are available.

Conclusions. For the following reasons, EPA concludes that 0.80 lb/mmBtu is a reasonable emission limitation that meets the requirements of section 407(b)(2). First, combustion controls applied to vertically fired boilers are an available technology that meets the cost-comparability requirement. Second, an emission limit of 0.80 lb/mmBtu is a level that 97.0% of vertically fired boiler population should be able to meet with the application of combustion controls at 40% NO_X removal efficiency. Third, the cost impact on electricity consumers of using this control technology to meet the recommended emission limit is small and similar in magnitude to the energy impact of using LNBs on Group 1 boilers. Finally, the recommended emission limit results in a reduction of NO_X emissions by approximately 57,000 tons per year without increases in CO, CO_2, SO_2, or solid waste disposal. As discussed in section II.D, there are substantial human health and environmental benefits associated with the additional NO_X reductions and meeting the proposed emission limitation is a cost-effective means of achieving such reductions.

5. FBC Boilers

The FBC boilers affected by the Title IV are inherently low NO_X emitters. Table 24 shows the CEM-measured emission rates of all Title IV-affected FBC boilers.

TABLE 24.—NO_X EMISSION RATES FOR TITLE IV-AFFECTED FBC BOILERS

Plant name	Boiler I.D.	NO_X emission rate (lb/mmBtu)
Nucla	1	0.170
Shawnee	10	0.230
Black Dog	2	0.258
R M Heskett	B2	0.286
TNP One	U1	0.169
TNP One	U2	0.153

Combustion controls are inherently included in the design of FBCs. Therefore, there is no additional cost involved with controlling NO_X from these boilers. EPA determined that applying a NO_X emission limitation to FBC boilers would result in no additional NO_X reductions since all these boilers are currently controlled. Observing the uncontrolled emissions of each boiler in the FBC boiler population for which NO_X limits are to be set under section 407(b)(2), EPA determined how many of the boilers could achieve various NO_X emission levels. The following table shows the NO_X emission levels achievable by between 50% and 100% of the FBC boiler population.

TABLE 25

NO_X level (lb/mmBtu)	Number of boilers meeting NO_X level	Percent of boilers meeting NO_X level
0.29	6	100
0.26	5	83.3
0.23	4	66.7
0.17	3	50.0

Table 25 indicates that 100% of the 6 FBC boilers can achieve a NO_X controlled emissions rate of 0.29 lb/mmBtu.

Conclusions. For the following reasons, EPA concludes that 0.29 lb/mmBtu is a reasonable emission limitation that meets the requirements of section 407(b)(2). First, combustion controls applied to FBC boilers are an available technology that meets the cost-comparability requirement. Second, an emission limit of 0.29 lb/mmBtu is a level that 100% of FBC boiler population should be able to meet with the application of combustion controls. Third, while the recommended limit will not result in any additional NO_X emission reductions (or in any increases in other pollutants or solid waste), the use of this control technology to meet the recommended emission limit imposes no additional cost on electricity consumers.

G. General Issues Raised

The Agency has received some public comment that, for some boiler types, some additional time should be provided for further demonstration of NO_X control technologies. Some commenters have suggested that EPA extend the Phase II NO_X compliance date for certain boiler types beyond January 1, 2000 and encourage, in the meantime, demonstration projects for such boiler types utilizing various control technologies. While EPA believes that the record supports establishment of the NO_X emission limitations, discussed above, for Group II boiler types in accordance with section 407(b)(2) of the Act, the Agency wants to ensure that the broadest range of constructive comment is elicited during the public comment period. For this reason, the Agency requests comment on, but does not propose, an alternative regulatory approach for specified boiler types that would incorporate the elements of postponement of compliance and encouragement of demonstration projects. Commenters should address the merits of the alternative approach with regard to specific Group II boiler types and whether such an approach would be consistent with the legal requirements of section 407(b)(2) and environmental goals of title IV.

Under this alternative regulatory approach, the compliance deadline for the specified boiler types for meeting Phase II NO_X emission limitations would be postponed for a short period (perhaps 2 years). Starting on the new compliance date, the applicable NO_X emission limitation for affected units of such boiler types would be the limitation set forth in today's proposed rule. However, a limited number of such units (perhaps 10 units), encompassing a range of annual operating capabilities, would be allowed to elect to comply early (i.e., on January 1, 2000) with a slightly higher NO_X emission limitation, which would become their applicable emission limitation for Phase II.

Each early-election unit would have to implement either: combustion controls designed to achieve a specified minimum percent reduction (perhaps 20 to 30 percent) in the uncontrolled NO_X emission rate; or an alternative NO_X control technology designed to achieve a specified minimum percent reduction (perhaps 40–50 percent). The unit could be incorporated in a NO_X averaging plan in accordance with § 76.11 during Phase II, using its applicable emission limitation. If the unit was unable to meet its applicable emission limitation, it could apply for an AEL in accordance with § 76.10.

EPA has also received comment concerning the desirability of allowing trading of NO_X emission reductions. EPA notes that it has previously considered and rejected, as outside the statutory scheme of section 407, the suggestion that banking of NO_X reductions be allowed as part of NO_X averaging plans 59 FR 13538, 13562 (March 22, 1994). The Agency seeks further comment on the legal basis and workability of a NO_X trading system. EPA has supported NO_X emissions trading for several years through a variety of programs developed by States under EPA's Economic Incentive Program. Examples include Massachusetts' Innovative Market Program for Air Credit Trading (IMPACT) for NO_X, VOC and CO, and Texas' Emissions Credit Banking and Trading Program for NO_X and VOC. In Los Angeles, NO_X emissions trading has been underway for more than a year through the South Coast Air Quality Management District's Regional Clean Air Incentive Market (RECLAIM).

Regional emissions trading is currently being considered for the eastern region of the US to address the persistent ozone non-attainment problems of many eastern States, due in part to the interstate transport of NO_X emissions. The Ozone Transport Commission (OTC), with support from EPA, is developing a model NO_X trading rule to be adopted by each of its twelve member States and the District of Columbia. Under a program similar to the Acid Rain Program for SO_2 emissions, NO_X emissions from utility boilers and large industrial boilers would be reduced significantly during the five-month ozone season under an emissions cap, but would allow for trades of NO_X emission allowances across State lines. The Ozone Transport Assessment Group (OTAG), with support from EPA, is considering a corresponding program for NO_X emissions from utilities and large industrial boilers for the 37 States in its region, including the States of the Ozone Transport Region. The possibility of including other sources of NO_X emissions, such as heavy-duty diesel engines and car fleets, through other types of emissions credit trading programs, is currently being examined.

The promulgation of EPA's Open Market Trading Rule will offer another option for States to consider in developing market incentive programs to reduce NO_X emissions. States will receive automatic EPA approval provided they adopt an identical version of EPA's model rule; variations on the model rule will also be readily approved as long as its implementation would not interfere with the State's attainment or maintenance strategies. Under EPA's Open Market Trading Rule, sources will be able to generate tradeable Discrete Emission Reduction (DER) credits for voluntarily reducing their NO_X or other emissions, provided the reduction is real and verifiable, and which, in turn, may be used by a purchaser to obtain flexibility in complying with an emissions limitation requirement. The open market trading program will enable States to offer both stationary and mobile sources the opportunity to achieve cost savings and emissions reduction flexibility, while providing an incentive for the development of new emissions reduction technologies.

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V. Regulatory Requirements

A. Docket

A docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The contents of the docket, except for interagency review materials, will serve as the record in case of judicial review (section 307(d)(7)(A)).

B. Executive Order 12866

Under Executive Order 12866 (58 Fed. Reg. 51735, October 4, 1993), the Agency must determine whether the regulatory action is ''significant'' and therefore subject to Office of

Management and Budget (OMB) review and the requirements of the Executive Order. The Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

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

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

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

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

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is a ''significant regulatory action'' because it will have an annual effect on the economy of approximately $143 million. As such, this action was submitted to OMB for review. Any written comments from OMB to EPA and any written EPA response to those comments are included in the docket. The docket is available for public inspection at the EPA's Air Docket Section, which is listed in the **ADDRESSES** section of this preamble.

The EPA does not anticipate major increases in prices, costs, or other significant adverse effects on competition, investment, productivity, or innovation or on the ability of U.S. enterprises to compete with foreign enterprises in domestic or foreign markets due to the final regulations.

In assessing the impacts of a regulation, it is important to examine (1) the costs to the regulated community, (2) the costs that are passed on to customers of the regulated community, and (3) the impact of these cost increases on the financial health and competitiveness of both the regulated community and their customers. The costs of this regulation to electric utilities are generally very small relative to their annual revenues. (However, the relative amount of the costs will definitely vary in individual cases.) Moreover, EPA expects that most or all utility expenses from meeting NO_X requirements will be passed along to ratepayers. When fully implemented in the year 2000, consumer electric utility rates are expected to rise by 0.07 percent on average due to this rulemaking. Consequently, the regulations are not likely to have an impact on utility profits or competitiveness.

C. Unfunded Mandates Act

Section 202 of the Unfunded Mandates Reform Act of 1995 (''Unfunded Mandates Act'') (signed into law on March 22, 1995) requires that the Agency must prepare a budgetary impact statement before promulgating a rule that includes a Federal mandate that may result in expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any one year. The budgetary impact statement must include: (i) Identification of the Federal law under which the rule is promulgated; (ii) a qualitative and quantitative assessment of anticipated costs and benefits of the Federal mandate and an analysis of the extent to which such costs to State, local, and tribal governments may be paid with Federal financial assistance; (iii) if feasible, estimates of the future compliance costs and any disproportionate budgetary effects of the mandate; (iv) if feasible, estimates of the effect on the national economy; and (v) a description of the Agency's prior consultation with elected representatives of State, local, and tribal governments and a summary and evaluation of the comments and concerns presented. Section 203 requires the Agency to establish a plan for obtaining input from and informing, educating, and advising any small governments that may be significantly or uniquely impacted by the rule.

In examining the impacts of this proposed regulation, EPA analyzed the following three regulatory scenarios:

1. Revising the existing Group 1 boiler emission limits for application to Phase II, Group 1 boilers and not establishing any emission limits for Group 2 boilers (resulting in the control of approximately 212,000 tons of NO_X per year at an annual total cost of approximately $56 million).

2. Revising the existing Group 1 boiler emission limits for application to Phase II, Group 1 boilers and establishing emission limits for Group 2 boilers (resulting in the control of approximately 831,000 tons of NO_X per year at an annual total cost of approximately $143 million).

3. Revising the existing Group 1 boiler emission limits for application to Phase II, Group 1 boilers and not establishing any emission limits for Group 2 boilers, however exempting cyclones less than 80 MWe (resulting in the control of approximately 830,000 tons of NO_X per year at an annual total cost of approximately $143 million).

Under section 205 of the Unfunded Mandates Act, EPA must identify and consider a reasonable number of regulatory alternatives before promulgating a rule for which a budgetary impact statement must be prepared. The Agency must select from those alternatives the most cost-effective and least burdensome alternative that achieves the objectives of the rule unless the Agency explains why this alternative is not selected or unless the selection of this alternative is inconsistent with law. In this proposal, the Agency discusses several regulatory options and their associated costs. In addition, the Agency has initiated but not completed consideration of other regulatory options beyond the options discussed in the proposal. The Agency believes that, among the options considered thus far and based on the current record, the proposal is the least costly, most effective, and least burdensome alternative that achieves the objectives of title IV and section 407 in particular. As discussed above, the Agency is soliciting comment on, not only the regulatory options discussed in the proposal, but also on any additional regulatory options. Commenters should also address what options are the least costly and least burdensome. After completion of the comment period, during which the Agency anticipates receiving comments on the full range of potential regulatory options and their related costs, EPA will make a final determination of what option is the least costly, most effective, and least burdensome, consistent with title IV.

Because this proposed rule is estimated to result in the expenditure by State, local, and tribal governments and the private sector, in aggregate, of over $100 million per year starting in 2000, EPA has addressed budgetary impacts in the Regulatory Impact Analysis, as summarized below.

The proposed rule is promulgated under section 407(b)(2) of the Clean Air Act. Total expenditures resulting from the rule are estimated at: $143 million per year starting in 2000. There are no federal funds available to assist State, local, and tribal governments in meeting these costs. There are important benefits from NO_X emission reductions because atmospheric emissions of NO_X have adverse impacts on human health and welfare and on the environment.

The proposed rule does not 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.[22] On the contrary, the rule

[22] As shown in EPA's Unfunded Mandates Act Analysis, as a result of this proposal, State and municipality owned boilers experience average

will result in only a minimal increase in average electricity rates. Moreover, the rule will not have a material effect on the national economy.

In developing the proposed rule, EPA provided numerous opportunities for consultation with interested parties, including State, local, and tribal governments, at public conferences and meetings. EPA evaluated the comments and concerns expressed, and the proposed rule reflects, to the extent consistent with section 407 of the Clean Air Act, those comments and concerns. These procedures will ensure State and local governments an opportunity to give meaningful and timely input and obtain information, education, and advice on compliance. Additionally, the EPA will initiate consultations with the affected State and local governments. The 25 State and municipality owned utilities will be provided by EPA with a brief summary of the proposal and the estimated impacts.

As described in EPA's analysis (see docket item II–F–4, Unfunded Mandates Reform Act Analysis for the Nitrogen Oxides Emission Reduction Program Under the Clean Air Act Amendments Title IV), the costs to some small municipality or State owned utilities, are higher than for large utilities, which tend to be privately held. However, the analysis indicates that the cost increase is relatively small even for utilities owned by municipalities and States.

D. Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* An Information Collection Request (ICR) document will be prepared by EPA and a copy may be obtained from Sandy Farmer, OPPE Regulatory Information Division; U.S. Environmental Protection Agency (2136), 401 M St. SW., Washington, DC 20460, or by calling (202) 260–2740.

The annual public reporting and recordkeeping burden for this collection of information is estimated to average 9 hours per response. This estimate includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to respond to a collection of information; search existing data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

No person is required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are displayed in 40 CFR Part 9.

Send comments regarding the burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to Chief, OPPE Regulatory Information Division; U.S. Environmental Protection Agency (2136), 401 M St., SW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503, marked ''Attention: Desk Officer for EPA.'' Include the ICR number in any correspondence. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

E. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. § 601, *et seq.*) requires EPA to consider potential impacts of proposed regulations on small business ''entities.'' If a preliminary analysis indicates that a proposed regulation would have a significant economic impact on 20 percent or more of small entities, then a regulatory flexibility analysis must be prepared.

Current Regulatory Flexibility Act guidelines indicate that an economic impact should be considered significant if it meets one of the following criteria: (1) Compliance increases annual production costs by more than 5 percent, assuming costs are passed onto consumers; (2) compliance costs as a percentage of sales for small entities are at least 10 percent more than compliance costs as a percentage of sales for large entities; (3) capital costs of compliance represent a ''significant'' portion of capital available to small entities, considering internal cash flow plus external financial capabilities; or (4) regulatory requirements are likely to result in closures of small entities.

Under the Regulatory Flexibility Act, a small business is any ''small business concern'' as identified by the Small Business Administration under section 3 of the Small Business Act. As of January 1, 1991, the Small Business Administration had established the size threshold for small electric services companies at 4 million megawatt hours per year. EPA's initial estimates are that the burden on small utilities under Phase II is minimal.

Pursuant to the provisions of 5 U.S.C. § 605(b), I hereby certify that this rule, if promulgated, will not have a significant adverse impact on a substantial number of small entities.

F. Miscellaneous

In accordance with section 117 of the Act, publication of this rule was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

List of Subjects in 40 CFR Part 76

Environmental protection, Acid rain program, Air pollution control, Nitrogen oxide, Reporting and recordkeeping requirements.

Dated: December 18, 1995.

Carol M. Browner,

Administrator.

For the reasons set out in the preamble, 40 CFR part 76 is amended as follows:

PART 76—[AMENDED]

1. The authority citation for part 76 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651 *et seq.*

2. Section 76.2 is amended by revising the definition of ''coal-fired utility unit'' and ''wet bottom'' and adding definitions for ''combustion controls'', ''fluidized bed combustor boiler'', ''non-plug-in combustion controls'', ''plug-in combustion controls'', and ''vertically fired boiler'', to read as follows:

§ 76.2 Definitions.

* * * * *

Coal-fired utility unit means a utility unit in which the combustion of coal (or any coal-derived fuel) on a Btu basis exceeds 50.0 percent of its annual heat input during the following calendar year: for Phase I units, in calendar year 1990; and, for Phase II units, in calendar year 1995 or, for a Phase II unit that did not combust any fuel that resulted in the generation of electricity in calendar year 1995, in any calendar year during the period 1990–1995. For the purposes of this part, this definition shall apply notwithstanding the definition in § 72.2 of this chapter.

* * * * *

Combustion controls means technology that minimizes NO_X formation by staging fuel and combustion air flows in a boiler. This definition shall include low NO_X burners, overfire air, or low NO_X burners with overfire air.

* * * * *

control costs of 0.110 mills/kWh while the national average control costs are 0.109 mills/kWh.

Fluidized bed combustor boiler means a boiler in which crushed coal, in combination with inert material (e.g., silica, alumina, or ash) and air, is maintained in a turbulent, suspended state and is combusted at relatively low temperatures.

* * * * *

Non-plug-in combustion controls means the replacement, in a cell burner boiler, of the portions of the waterwalls containing the cell burners by new portions of the waterwalls containing low NO_X burners or low NO_X burners with overfire air.

* * * * *

Plug-in combustion controls means the replacement, in a cell burner boiler, of existing cell burners by low NO_X burners or low NO_X burners with overfire air.

* * * * *

Vertically fired boiler means a dry bottom boiler with circular burners, or coal and air pipes, oriented downward and mounted on waterwalls that are horizontal or at an angle. This definition shall include dry bottom arch-fired boilers, dry bottom roof-fired boilers, and dry bottom top-fired boilers and shall exclude dry bottom turbo-fired boilers.

* * * * *

Wet bottom means that the ash is removed from the furnace in a molten state. The term ''wet bottom boiler'' shall include: wet bottom wall-fired boilers, including wet bottom turbo-fired boilers; and wet bottom boilers otherwise meeting the definition of vertically fired boilers, including wet bottom arch-fired boilers, wet bottom roof-fired boilers, and wet bottom top fired boilers. The term ''wet bottom boiler'' shall exclude cyclone boilers and tangentially fired boilers.

§ 76.5 [Amended]

3. Section 76.5 is amended by removing paragraph (g).

4. Section 76.6 is added to read as follows:

§ 76.6 NO_X emission limitations for Group 2 boilers.

(a) Beginning January 1, 2000 or, for a unit subject to section 409(b) of the Act, the date on which the unit is required to meet Acid Rain emission reduction requirements for SO_2 , the owner or operator of a Group 2, Phase II coal-fired boiler with a cell burner boiler, cyclone boiler, a wet bottom boiler, a vertically fired boiler, or a fluidized bed combustor boiler shall not discharge, or allow to be discharged, emissions of NO_X to the atmosphere in excess of the following limits, except as provided in §§ 76.11 or 76.12:

(1) 0.68 lb/mmBtu of heat input on an annual average basis for cell burner boilers. The NO_X emission control technology on which the emission limitation is based is plug-in combustion controls or non-plug-in combustion controls. Except as provided in § 76.5(d), the owner or operator of a unit with a cell burner boiler that installs non-plug-in combustion controls prior to January 1, 2000 shall comply with the emission limitation applicable to cell burner boilers.

(2) 0.94 lb/mmBtu of heat input on an annual average basis for cyclone boilers. The NO_X emission control technology on which the emission limitation is based is coal reburning, natural gas reburning, or selective catalytic reduction.

(3) 0.86 lb/mmBtu of heat input on an annual average basis for wet bottom boilers. The NO_X emission control technology on which the emission limitation is based is combustion controls.

(4) 0.80 lb/mmBtu of heat input on an annual average basis for vertically fired boilers. The NO_X emission control technology on which the emission limitation is based is combustion controls.

(5) 0.29 lb/mmBtu of heat input on an annual average basis for fluidized bed combustor boilers. The NO_X emission control technology on which the emission limitation is based is fluid bed combustion controls.

(b) The owner or operator shall determine the annual average NO_X emission rate, in lb/mmBtu, using the methods and procedures specified in part 75 of this chapter.

5. Section 76.7 is added to read as follows:

§ 76.7 Revised NO_X emission limitations for Group 1, Phase II boilers.

(a) Beginning January 1, 2000, the owner or operator of a Group 1, Phase II coal-fired utility unit with a tangentially fired boiler or a dry bottom wall-fired boiler shall not discharge, or allow to be discharged, emissions of NO_X to the atmosphere in excess of the following limits, except as provided in §§ 76.8, 76.11, or 76.12:

(1) 0.38 lb/mmBtu of heat input on an annual average basis for tangentially fired boilers.

(2) 0.45 lb/ mmBtu of heat input on an annual average basis for dry bottom wall-fired boilers (other than units applying cell burner technology).

(b) The owner or operator shall determine the annual average NO_X emission rate, in lb/mmBtu, using the methods and procedures specified in part 75 of this chapter.

§ 76.8 [Amended]

6. Section 76.8 is amended by: removing from paragraph (a)(2) the words ''any revised NO_X emission limitation for Group 1 boilers that the Administrator may issue pursuant to section 407(b)(2) of the Act'' and adding, in their place, the words ''§ 76.7''; removing from paragraph (a)(5) the words ''§§ 76.5(g) and if revised emission limitations are issued for group 1 boilers pursuant to section 407(b)(2) of the Act,''; and removing from paragraphs (e)(3)(iii) (A) and (B) the words ''§ 76.5(g) and, if revised emission limitations are issued pursuant to section 407(b)(2) of the Act,''.

§ 76.10 [Amended]

7. Section 76.10 is amended by removing from paragraph (f)(1)(iii) the words ''§ 76.5(g) or 76.6'' and adding, in their place, the words ''§§ 76.6 or 76.7''.

Appendix B [Amended]

8. Appendix B is amended by: removing from the heading of Appendix B the words ''Group 1, Phase I'' and adding, in their place, the words ''Group 1''; removing from section 1 the words ''average cost'' and adding, in their place, the words ''distribution of costs''; removing from section 1 the words ''average capital costs and cost-effectiveness'' and adding, in their place, the words ''average capital costs and distribution of cost effectiveness''; removing from section 1, the introductory text of section 2, and section 2.4 the words ''Group 1, Phase I'' in each place that the words appear and adding, in their place, the words ''Group 1''; and removing and reserving section 3.

[FR Doc. 96–494 Filed 1–18–96; 8:45 am]

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