ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 76

[AD–FRL–5666–1]

RIN 2060–AF48

Acid Rain Program; Nitrogen Oxides Emission Reduction Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action promulgates standards for the second phase of the Nitrogen Oxides Reduction Program under Title IV of the Clean Air Act (''CAA'' or ''the Act'') by establishing nitrogen oxides (NO_X) emission limitations for certain coal-fired electric 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.

EFFECTIVE DATE: December 19, 1996.

ADDRESSES: *Docket.* Docket No. A–95–28, containing information considered during development of the promulgated standards, 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 (LE–131), Waterside Mall, Room M1500, 1st Floor, 401 M Street, SW, Washington, DC 20460. A reasonable fee may be charged for copying.

Background information document. The background information document containing responses to public comments on the proposed standards may be obtained from the docket. Please refer to ''Phase II Nitrogen Oxides Emission Reduction Program—Response to Comments Document''.

FOR FURTHER INFORMATION CONTACT: Peter Tsirigotis, Source Assessment Branch, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M Street S.W., Washington, DC 20460 (202–233–9620).

SUPPLEMENTARY INFORMATION:

Regulated Entities

Entities regulated by this action are electric service providers that run or operate coal-fired electric utility boilers including dry bottom wall-fired and tangentially fired boilers (Group 1) and certain other boiler types including boilers applying cell-burner technology, cyclone boilers, wet bottom boilers, and other types of coal-fired boilers (Group 2). Regulated entities and boilers include:

Regulated Entities	Regulated Boilers
Electric Service Providers.	Dry bottom wall-fired.
	Tangentially fired.
	Cell Burners.
	Cyclones (larger than 155 MWe).
	Vertically fired.
	Wet bottoms (larger than 65 MWe).

This table is not intended to represent a definitive enumeration of all existing and future entities regulated by this action. Rather, its intent is to provide a general guide for readers and to list entities that EPA is now aware will be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your (facility, company, business, organization, etc.) is regulated by this action, you should carefully examine the applicability criteria in §§ 72.6 and 76.1 of title 40 of the Code of Federal Regulations. If you have questions regarding the applicability of this action to a particular entity, consult the person named in the preceding ''For Further Information Contact'' section.

The information in this preamble is organized as follows:

I. Rule Background

A. Purpose of Acid Rain NO_X Emission Reduction Program

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 1970 passage of the Clean Air Act, NO_X has increased 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 total NO_X emissions and, from 1980 to 1990, their contribution rose to 32 percent of total NO_X emissions. In 1994, electric utility emissions represented about 33 percent of the total annual NO_X emissions. Approximately 90 percent of estimated electric utility NO_X emissions were attributed to coal combustion (see docket item IV–A–8 (USEPA, National Air Pollution Emission Trends, 1900–1994 (EPA–454/R–95–011) at 2–2, October 1995)).

The NO_X emissions discharged into the atmosphere from the burning of fossil fuels consists primarily of nitric oxide (NO). Much of the NO, however, reacts with organic radicals in the air to form nitrogen dioxide (NO_2) and, over longer periods of time, reacts with and forms other pollutants, including ozone (O_3), nitric acid (HNO_3) and fine particles. These 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, snow, or fog (''wet deposition'') or as gases (''dry deposition''), they contribute to acidification of lakes and streams and to excessive nitrogen loadings to estuaries and coastal water systems such as in the Chesapeake Bay (''eutrophication'').

NO_2 has been documented to cause eye irritation, either by itself or when oxidized photochemically into peroxyacetyl nitrate (PAN). Ozone, 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 adversely to morbidity and mortality.

B. Summary of Final Rule

1. NO_X Standards Promulgated by This Rule

EPA today is promulgating new emission limitations to be implemented for nitrogen oxides (NO_X) emissions for wall-fired and tangentially fired boilers (Group 1 boilers) and establishing emission limitations for certain other boilers (Group 2 boilers). The final rule implements section 407 (b)(2) of the Act, which applies to NO_X emission limitations for Group 1 and Group 2 boilers during Phase II of the Acid Rain Program (January 1, 2000 and beyond). Under section 407(b)(2) the Administrator ''may revise'' the applicable NO_X emission limitations for Group 1 boilers in Phase II if the Administrator determines that ''more effective low NO_X burner technology is available,'' i.e., that data on the effectiveness of low NO_X burner technology (LNB) installed after passage of the Clean Air Act Amendments of 1990 supports emission limitations more stringent than the limitations established for Group 1 boilers during Phase I of the Acid Rain Program pursuant to section 407(b)(1) of the Act. 42 U.S.C. 7651f(b)(2). Also under section 407(b)(2) of the Act, the Administrator must establish NO_X emission limitations (on a lb/mmBtu annual average basis) for Group 2 boilers, which include wet bottom boilers, cyclone boilers, cell burner boilers, and all other types of utility boilers not classified as dry bottom wall-fired and tangentially fired boilers, and must meet certain requirements in establishing these limitations. In setting the final emission limitations for Group 1 and Group 2 boilers, as summarized below, the Administrator has met the requirements in section 407(b)(2) of the Act.

i. Revision of NO_X Emission Limits for Phase II, Group 1 Boilers

The Agency has developed a computerized database containing detailed information on the characteristics and emission rates of all coal-fired units with Group 1 boilers on which low NO_X burners (LNBs) have been installed without any other NO_X controls, and for which EPA has both quality assured long-term post-retrofit hourly NO_X emission rate data, measured by continuous emission monitoring systems (CEMS), certified pursuant to 40 CFR part 75 (Acid Rain Continuous Emission Monitoring Rule), and quality assured short-term CEM or test data measurements of uncontrolled emission rates. This database, called the ''LNB Application Database,'' consists of 39 dry bottom wall-fired boilers and 14 tangentially fired boilers and forms the technical basis for EPA's evaluation of the effectiveness (percent NO_X removal) of LNBs applied to Group 1 boilers.

For the final rule, EPA has adopted a methodology that employs ''load-weighted annual average NO_X emission rates'' over the full ''post-optimization period'' for evaluating the effectiveness of LNBs. The post-optimization period includes all available data beginning with the first hour of the low NO_X period,[1] when the LNBs were operating under optimized NO_X removal conditions, and extending to the end of the entire data set, i.e., through June 30, 1996, the end of the latest available reporting period from the Acid Rain Emissions Tracking System (ETS). The post-optimization period contains quality assured CEM data spanning at least 4 calendar months for every boiler and at least 11 calendar months for most boilers (83%). In addition, EPA applied a NO_X/load weighting scheme, using hourly load data reported for 1995, to develop ''load-weighted'' annual average NO_X emission rates from the data set (see discussion in section III.A.2.iii of this preamble). Two advantages of using load-weighted annual average NO_X emission rates over the post-optimization period are that the criteria used to define the ''post-optimization period'' take into account the site-specific nature of the LNB equipment optimization and operator training processes while the use of ''load weighting'' accounts for any potential impact of annual load dispatch patterns on NO_X emissions.

Following the identification of appropriate LNB applications and time period for analysis, EPA developed a two-part model to estimate: (1) Annual average emission rates that can be sustained by LNBs installed on Phase II units with Group 1 boilers and (2) percentile distributions of Phase II units that can comply with various performance standards. The first part of the model calculates the percent reduction achievable by LNBs as a function of uncontrolled emission rate, and the second part applies the estimated percent reduction 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. EPA used the percentile distributions to select reasonably achievable emission limits for the two types of Group 1 boilers, where ''reasonably achievable'' is defined as the controlled emission rate 85 to 90 percent of the affected population of units can meet or exceed on an annual average basis.

EPA concludes that more effective low NO_X burner technology is available for dry bottom wall-fired and tangentially fired boilers. Further, EPA concludes that for dry bottom wall-fired boilers, 0.46 lb/mmBtu is a reasonable emission limitation that is achievable using such technology. EPA estimates that 85 to 90% of the Phase II dry bottom wall-fired boilers can achieve this emission rate. The implementation of this standard, will result in an additional NO_X emissions reduction of approximately 90,000 tons per year, beginning in 2000, below the emission levels anticipated under the Phase I Acid Rain NO_X Emission Reduction Rule (60 FR 18751, April 13, 1995).

Finally, EPA concludes that for tangentially fired boilers, 0.40 lb/mmBtu is a reasonable emission limitation that is achievable using such technology. EPA estimates that 85 to 90% of the Phase II tangentially fired boilers can achieve this emission rate. The implementation of this standard will result in an additional NO_X emissions reduction of approximately 30,000 tons per year, beginning in 2000, below the emission levels anticipated under the Phase I Acid Rain NO_X Emission Reduction Rule. As discussed below, EPA exercises its discretion under section 407(b)(1) to adopt these revised Group 1 NO_X emission limitations because the resulting additional reductions are a reasonable step toward achieving necessary, significant NO_X reductions and are consistent with the guideline in section 401(b) concerning the level of NO_X reductions to be achieved.

ii. Establishment of 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, EPA determines what NO_X control technologies are the best systems of continuous emission reduction available for each category of Group 2 boilers. 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, applied to Group 1 boilers.

Second, EPA evaluates each such NO_X control technology and estimates 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 compares the dollar cost per ton of NO_X removed for each

[1] The ''low NO_X period'' EPA used for assessing performance of LNBs applied to Group 1 boilers was defined by identifying the lowest average NO_X emission rate each boiler has sustained for at least 52 days, i.e., over a period of 1,248 hours when the boiler was operating and valid CEM data, measured by CEMS certified pursuant to 40 CFR part 75, were available. (Data for 30 calendar days following estimated date boiler began operating after shutdown for LNB retrofit are not used when making this determination. See Table 1, DQO #4D).

NO_X control technology applied to the Group 2 boiler category to the dollar cost per ton of NO_X removed for low NO_X burners applied to dry bottom wall-fired and tangentially fired boilers. Based on this comparison, EPA determines whether the NO_X control technology applied to the Group 2 boiler category has a cost-effectiveness comparable to that of LNBs applied to Group 1 boilers.

Third, EPA estimates the percent change in electricity rates for consumers resulting from costs (in mills per kilowatt-hour) associated with the application of emission limitations on Group 2 boilers. This value is then compared to the percent change in nationwide electricity rates due to the establishment of emission limitations for LNBs on Group 1 boilers. EPA also estimates the emission reductions that are likely to be achieved and considers any other environmental impacts likely to result from application of each NO_X control technology.

Fourth, EPA assesses the performance (percent NO_X reduction) of each cost-comparable Group 2 control technology and applies that 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. The emission limitation that will be achievable by 85 to 90% of the boiler population is generally selected, after taking account of energy and environmental impacts, as the emission limitation for that category of Group 2 boiler.

EPA concludes that for cell-burner fired boilers, 0.68 lb/mmBtu is a reasonable emission limitation that meets the requirements of section 407(b)(2). For cell burner boilers, plug-in retrofits and non-plug in retrofits are the best continuous control systems that are available and meet the cost comparability requirement. EPA bases the emission limitation on the use of these control technologies and estimates that 80% of the cell burner population can achieve the limitation. The energy impact, i.e., impact of mills/kWh cost on electricity consumers, of using these technologies to meet the emission limitation is small and similar in magnitude to the energy impact of using LNBs on Group 1 boilers. The emission limitation will result in a total NO_X emissions reduction of approximately 420,000 tons per year, beginning in 2000, without significant increases in other air pollutants or solid waste. As discussed below, the resulting NO_X reductions are a reasonable step toward achieving necessary, significant NO_X reductions and are consistent with section 401(b).

EPA concludes that for cyclone fired boilers larger than 155 MWe, 0.86 lb/mmBtu is a reasonable emission limitation that meets the requirements of section 407(b)(2). For cyclone fired boilers, gas reburning, and SCR are the best continuous control systems that are available and meet the cost comparability criteria. The energy impact, i.e., impact of mills/kWh cost on electricity consumers, of using these technologies to meet the emission limitation is small and similar in magnitude to the energy impact of using LNBs on Group 1 boilers. EPA bases the emission limitation on the use of these technologies and estimates that 85 to 90% of the cyclone fired boiler population can achieve the emission limitation. The emission limit will result in a total NO_X emissions reduction of approximately 225,000 tons per year, beginning in 2000, without significant increases in other air pollutants or solid waste. As discussed below, the resulting NO_X reductions are a reasonable step toward achieving necessary, significant NO_X reductions and are consistent with section 401(b). EPA has decided not to set a NO_X emission limitation for cyclone boilers of 155 MWe or less.

EPA concludes that for wet bottom boilers larger than 65 MWe, 0.84 lb/mmBtu is a reasonable emission limitation that meets the requirements of section 407(b)(2). For wet bottom boilers, gas reburning, and SCR are the best continuous control systems that are available and meet the cost comparability requirement. EPA bases the emission limitation on the use of these technologies and estimates that 85 to 90% of the wet bottom boiler population can achieve the emission limitation. The energy impact, i.e., impact of mills/kWh cost on electricity consumers, of using these technologies to meet the emission limitation is small and similar in magnitude to the energy impact of using LNBs on Group 1 boilers. The emission limitation will result in a total NO_X emissions reduction of approximately 80,000 tons per year, beginning in 2000, without significant increases in other air pollutants or solid waste. As discussed below, the resulting NO_X reductions are a reasonable step toward achieving necessary, significant NO_X reductions and are consistent with section 401(b). EPA has decided not to set a NO_X emission limitation for wet bottom boilers of 65 MWe or less.

EPA concludes that for vertically fired boilers 0.80 lb/mmBtu is a reasonable emission limitation that meets the requirements of section 407(b)(2). For vertically fired boilers, combustion controls are the best continuous control system available and meet the cost comparability requirement. EPA bases the emission limitation on the use of these technologies and estimates that 85 to 90% of the vertically fired boiler population can achieve this emission limitation. The energy impact, i.e., impact of mills/kWh cost on electricity consumers, of using these technologies to meet the emission limitation is small and similar in magnitude to the energy impact of using LNBs on Group 1 boilers. The emission limitation will result in a total NO_X emissions reduction of approximately 45,000 tons per year, beginning in 2000, without significant increases in other air pollutants or solid waste. As discussed below, the resulting NO_X reductions are a reasonable step toward achieving necessary, significant NO_X reductions and are consistent with section 401(b). EPA has decided not to set a NO_X emission limitation for arch-fired boilers, a subset of the vertically fired boiler category.

Finally, EPA has decided not to set a NO_X emission limitation for FBC boilers. Because these units are already low NO_X emitters by design, the NO_X emissions reduction achieved by installing any additional control technology, would not meet the cost-comparability requirement of section 407(b)(2). Moreover, setting an emission limitation that can be achieved by every existing FBC boiler without installing any additional control technology would have an adverse environmental impact. Some existing boilers emit at rates considerably below the highest annual rate observed among FBC boilers and these boilers could offset the emission reductions otherwise required of other affected boilers through emissions averaging under § 76.10.

EPA has also decided not to set a NO_X emission limitation for stoker boilers. EPA has not found any continuous control technology for stoker boilers that meets the cost-comparability requirement.

2. Rationale for Revising Group 1 NO_X Emission Limits and Environmental Impact of Group 2 NO_X Emission Limits

EPA is exercising its discretion to revise the Phase II, Group 1 NO_X emission limitations because: (1) NO_X emissions have significant adverse effects on human health and the environment; (2) significant, additional regional NO_X reductions from current levels are likely to be necessary; (3) without additional actions NO_X emissions are projected to increase nationwide starting in 2002; (4) the revision of Phase II, Group 1 emission limitations is one of the most cost-effective means of achieving additional NO_X reductions; and (5) the additional reductions from the revision represent a reasonable step toward achieving necessary NO_X reductions. In addition, the resulting NO_X reductions are consistent with section 401(b). The adverse health and environmental effects of NO_X emissions are discussed in the proposed rule on Phase II NO_X emission limitations. 61 FR 1442, 1453–55, January 19, 1996. EPA reaffirms that discussion, which summarizes the adverse impact of NO_X emissions through: The formation of ozone, particulate matter, and nitrogen oxides; and atmospheric deposition resulting in eutrophication of water bodies and acidification of lakes and streams. For the same reasons, EPA also concludes that the adoption of the Group 2 emission limitations set forth in today's rule is supported by the environmental impact of the emission reductions that will result.

The contribution of nitrogen oxides to the formation of ozone, acid deposition and eutrophication of water bodies is substantial. Consequently, in order to address these problems, significant NO_X emission reductions are likely to be needed on a regional scale, particularly in the eastern half of the U.S. This is the portion of the nation in which most of the boilers subject to NO_X emission limitations under the Acid Rain Program are located; 87% of Phase II, Group 1 boilers and 89% of Group 2 boilers covered by today's final rule are in the eastern U.S.

i. Ozone

With regard to ozone, additional regional NO_X reductions of at least 50% from current levels are likely to be needed over large portions of the nation to attain and maintain the national ambient air quality standard for ozone. Modeling results using EPA's Regional Oxidant Model (ROM) estimated that NO_X reductions of about 75% will be needed over large portions of the nation to reduce ozone concentrations to levels at or below the NAAQS (see docket item IV–J–8 (EXISTMOD.TXT, OTAG Modeling and Assessment Subgroup Files on EPA's TTN Bulletin Board, February 7, 1996)). The ROM modeling results were among the reasons for the formation of the Ozone Transport Assessment Group (OTAG), comprised of the 37 eastern-most States and tasked with developing a consensus approach for reducing regional NO_X emissions. OTAG recently completed atmospheric modeling simulations using SAI's Urban Airshed Model (UAM–V) (see docket item IV–J–21 (OTAG Air Quality Analysis Workgroup, 1996)). The results indicate that: broad NO_X emission reductions will decrease regional ozone, high ozone, and ozone in non-attainment areas; and NO_X emission reductions in each OTAG sub-region will be needed to both lower ozone in that same sub-region, as well as other sub-regions.

Further, necessary NO_X reductions to achieve or maintain the ozone standard have been estimated for several other areas of the country: 50–75% from 1990 levels throughout the Northeast Ozone Transport Region (OTR) (60 FR 4712, 4722, January 24, 1995); up to 90% reductions in the Southeast (see docket item II–I–98 (State of the Southern Oxidants Study, 1995)); and a combination of 75% reductions for NO_X and 25% for VOCs regionally, combined with 25% for NO_X and 75% for VOCs locally in the New York region (60 FR 4721); and significant NO_X reductions in the Lake Michigan area, not yet quantified. The results of a study analyzing ozone non-attainment in the eastern U.S. found that nationwide NO_X emission reductions of about 50% from 1990 levels will be needed to approach achievement of the necessary ozone standards (see docket item IV–J–9 (Rao, S.T., et.al., Dealing with the Ozone Non-Attainment Problem in the Eastern United States, AWMA journal, January 1996)).

ii. Acid Deposition

Similarly, additional, regional NO_X reductions of at least 40% are likely to be necessary in order to mitigate the effects of acid deposition. In particular, it is estimated that between 40–50% reductions of NO_X in the Eastern U.S. beyond those already required in the Clean Air Act may be necessary simply to keep the number of acidified lakes in the Adirondacks in New York at 1984 levels. (See docket item IV–A–6 (*Acid Deposition Standard Feasibility Study* (EPA 430–R–95–001a) at xvi).) Without additional reductions, the number of acidic lakes in the Adirondacks are projected to increase by almost 40% by 2040. *Id.* at 47. Significant, additional reductions may also be necessary with regard to the Mid-Appalachian region (see docket item IV–A–6 (*Acid Deposition Standard Feasibility Study* at xvi)).

iii. Eutrophication

NO_X emissions also contribute significantly to eutrophication, i.e., an overabundance of nitrogen to water bodies that leads to problems of nutrient enrichment. Regional NO_X emission reductions of up to 40% are likely to be needed. The signatories to the Chesapeake Bay Agreement, (Maryland, Pennsylvania, Virginia, the District of Columbia, the Chesapeake Bay Commission, and the federal government) have agreed on a goal of a 40% reduction in nitrogen loadings to the Bay by 2000 (relative to a 1985 baseline), representing a reduction of 34 million kilograms of nitrogen (see docket item IV–J–11 (Hicks et al., 1995:6)). In addition, they agreed to maintain, after 2000, a cap on nitrogen loadings at 60% of baseline loadings. Present estimates are that approximately 27% of total nitrogen loading to the Bay system comes from atmospheric sources in the form of NO_X emissions (see docket items IV–J–26 (Linker et al., 1993) and IV–J–19 (Valigura et al., 1995)). Since reducing nitrogen loading through the control of NO_X emissions can be as cost-effective as controlling non-atmospheric sources of nitrogen loading (e.g., point sources such as waste water treatment and non-point sources such as farms), up to a 40% reduction of the contribution in NO_X emissions to the Bay in areas contributing to the eutrophication of the Bay is likely to be necessary.

Although the watershed of the Chesapeake Bay encompasses approximately 64,000 square miles, the Chesapeake Bay ''airshed,'' which is the contiguous area providing 70% of the atmospheric deposition loads to the watershed (see docket item IV–J–18 (Dennis, 1996)), covers up to 600,000 square miles in area (see docket item IV–J–3 (Valigura et al., 1996:23)). The airshed extends upwind of, as well as bordering the water body itself: south to South Carolina, north to Ontario, Canada, and westward up to 500 miles (see docket item IV–J–11 (Hicks et al., 1995:6)). NO_X emissions from outside this area not only contribute to eutrophication in the Bay but also to the entire coastline, such as from the Carolinas to New York (see docket item IV–J–3 (Valigura et al., 1996:23)).

iv. Utility Contribution to Atmospheric NO_X Emissions

Electric utilities contributed approximately 33% of total atmospheric NO_X emissions in 1994, thus substantially contributing to ozone formation, acid deposition, and eutrophication.

Table 1 summarizes the reductions in atmospheric NO_X emissions likely needed and the additional reductions provided by today's final rule. Although the additional reductions from coal-fired utility boilers under the final rule are substantial, they represent only about 5% of all atmospheric NO_X emissions from all sources of NO_X emissions. The additional reductions under the final rule represent about a 15% reduction in total utility emissions. Since utilities presently contribute about 33% of total NO_X emissions, the final rule provides reductions of about 5% of total NO_X emissions. This reduction level is significantly less than the reduction level likely to be needed to mitigate ozone, acid deposition, and eutrophication (see docket item IV–A–8 (EPA, ''National Air Pollution Emission Trends, 1900–1994'' at 2–2, October, 1995, EPA–454/R–95–011)).

TABLE 1.—ESTIMATED REGIONAL REDUCTIONS NECESSARY TO MITIGATE VARIOUS ENVIRONMENTAL EFFECTS

	Environmental effect		
	Ozone	Acid deposition	Eutrophication
Regional NO_X Reductions Necessary.	More than 50%.	More than 40%.	Up to 40%
NO_X Reductions Achieved from the Final Rule as Percentage of Total NO_X Emissions.	5%	5%	5%

v. NO_X Reductions Not Sustained

Although national NO_X emissions are expected to decrease up to the year 2000, (see docket item IV–A–8 (EPA, ''National Air Pollution Emission Trends, 1900–1994'' at 5–5, October, 1995, EPA–454/R–95–011)), emissions are projected to begin increasing after 2000 (*id.* at 5–2 and 6–8 [2]). The existing NO_X control programs under the Clean Air Act (including the Mobile Source Program under title II and the Acid Rain NO_X Program under title IV) limit NO_X emission rates (e.g., the pounds of NO_X emissions per amount of fuel consumed (under title IV)) for emission sources. The programs do not cap the total tonnage of nationwide emissions. As the number of emission sources and the use of emission sources increases, reductions due to emission rate limitations are offset to an increasing extent. For this reason, after 2002, when implementation of these NO_X control programs is largely completed and growth in sources and source use continues, NO_X emissions will gradually increase for the foreseeable future (*id.* at 5–5). Section 401(b) of the Act suggested, as a guideline, that NO_X emissions should be reduced nationwide by 2 million tons from the 1980 level. By about 2006, total NO_X emissions will surpass that guideline unless additional efforts are made (e.g., under title IV) to reduce NO_X emissions (*See* figure 1, below). The projected increase in total NO_X emissions is well within the time frame considered by Congress in title IV. EPA notes that the nationwide annual cap for SO_2 emissions, also established under section 402, begins to apply in the year 2010. Until 2010, total annual allocated SO_2 allowances will exceed the cap, because of additional allowances allocated under section 409 for repowered units and bonus allowances under section 405. Additional NO_X reductions, such as these under today's final rule, are necessary both in light of the likely need to reduce NO_X to address ozone, acid deposition, and eutrophication, and in light of the NO_X reduction guideline in section 401(b) of the Act. In short, new initiatives are needed to reduce NO_X emissions on a regional scale in order to improve environmental quality and health beyond 2000.

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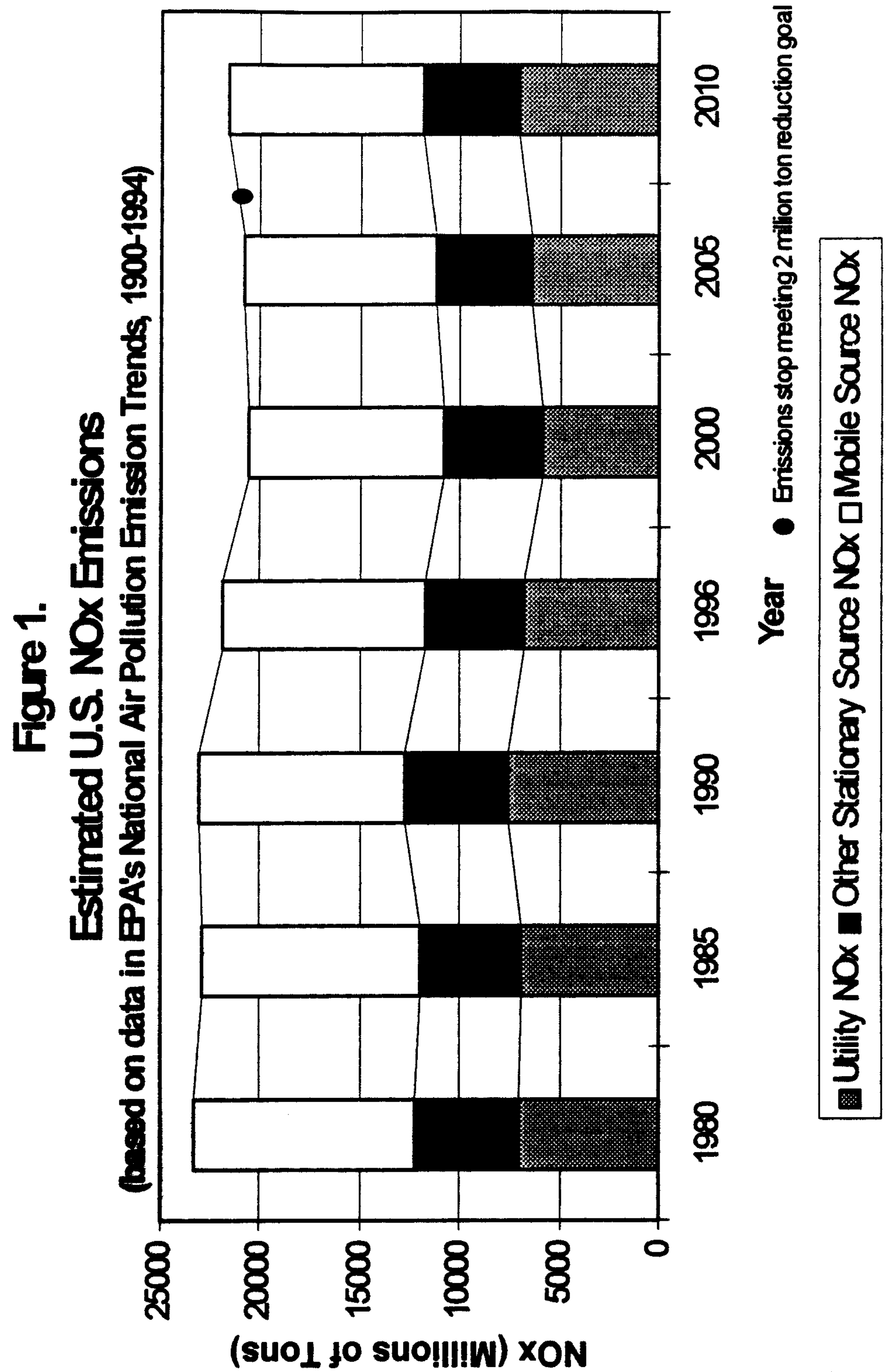
[2] Report's projections take into account requirements for Reasonably Available Control Technologies (RACT) under title I, enhanced programs for inspection and maintenance of mobile sources under title I, and title IV Group 1 emission limits promulgated April 13, 1995 (*id.* at 6–8, (assuming, for analytical purposes, that title IV emission limits are set at RACT)).



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vi. Cost-Effectiveness

The revision of Phase II, Group 1 emission limitations and establishment of Group 2 emission limitations is a cost-effective means of achieving the likely necessary, additional regional NO_X reductions. The control technologies on which the revised Group 1 limits and the Group 2 limits are based are more cost-effective (i.e., have a lower cost per ton of NO_X removed) when applied to the respective Group 1 and Group 2 boiler types than most other control technologies applied to these boiler types or to non-utility sources. As shown below, the dollar cost per ton of NO_X removed for reductions under the final rule is less than, or at the lower end of, the range of dollar cost per ton of NO_X removed for most alternative reductions. In short, the NO_X reductions achievable under this final rule are among the less expensive that can be made.

Utility Sources: For coal-fired utility boilers using higher level control technologies, (e.g., SCR with higher NO_X reduction capability) than the technologies on which the title IV limits are based, the average cost-effectiveness for typical wall-fired boilers ranges from $1,226/ton to $1,670/ton with percent reductions ranging from 60–90%. For typical tangentially fired boilers, the cost-effectiveness ranges from $1,439/ton to $1,935/ton with percent reductions ranging from 60–90%. For typical cyclone boilers, the cost-effectiveness ranges from $440/ton to $880/ton with percent reductions ranging from 60–90%. For typical cell-burner boilers, the cost-effectiveness ranges from $624/ton to $801/ton with percent reductions ranging from 60–80%. For typical wet bottom boilers, the cost-effectiveness ranges from $572/ton to $733/ton with percent reductions ranging from 60–90%. For typical roof-fired (vertically-fired) boilers, the cost-effectiveness ranges from $750/ton to $907/ton with percent reductions ranging from 60 to 90%. For typical oil and gas utility boilers, the average cost-effectiveness for wall-fired dual-fired boilers under various NO_X reduction technologies ranges from $748/ton to $2,263/ton with percent reductions ranging from 40–90%. For typical tangentially fired dual-fired boilers, the cost-effectiveness ranges from $507/ton to $1,573/ton with percent reductions ranging from 30–90% (see docket item IV–J–4 (Ozone Transport Assessment Group, Control Technologies and Options Workgroup, Final Report, April 11, 1996)).

As compared to the cost-effectiveness ranges for higher level control technologies applied to typical utility boilers, the average cost-effectiveness for meeting the Group 1 and Group 2 emission limits under today's final rule, using the control technologies on which the limits are based, is approximately $229/ton of NO_X removed.

Non-Utility Point Sources: Non-utility point sources NO_X reductions are less cost effective, on average, than NO_X reductions under today's final rule. For example, the average cost-effectiveness for process heaters ranges from $290–50,000/ton at an average reduction of 5–90%. For cement manufacturing, the average cost-effectiveness ranges from $470–4,870/ton at an average reduction of 20–90%. For wood manufacturing, the average cost-effectiveness ranges from $1,000 to over $10,000/ton at an average reduction of 0–60% (see docket item IV–J–4 (Ozone Transport Assessment Group, Control Technologies and Options Workgroup, Final Report, April 11, 1996)).

Mobile Sources: For mobile sources, the cost-effectiveness under various NO_X control options is also high, on average, as compared to reductions under today's final rule. For example, the average cost-effectiveness for light-duty on highway vehicles ranges from $1,100–$260,000/ton, with percent reductions ranging from 0.2–21%. For heavy-duty on highway vehicles, the average cost-effectiveness ranges from $1,000/ton to $40,000/ton, with percent reductions ranging from 0.02–5.6%. For non-road sources, the average cost-effectiveness ranges from $119/ton to $23,000/ton, with percent reductions ranging from 0.4–3.4% (see docket item IV–J–6 (Mobile Sources Assessment: NO_X and VOC Reduction Technologies for Application by the Ozone Transport Assessment Group, Final Report, March 4, 1996)).

Table 2 summarizes the cost-effectiveness ranges of NO_X controls for the three major NO_X emitting sources, as compared to the cost-effectiveness of reductions under the revised Group 1 limits and Group 2 limits.

Other: The reductions from applying control technologies to coal-fired power plants under today's final rule can be as cost-effective to achieve as reductions from other point sources (e.g., wastewater plants) and area sources (e.g., farms, animal pastures). Studies concerning eutrophication in the Chesapeake Bay estimate the following average cost-effectiveness of control technologies applied to non-utility sources: chemical addition or biological removal of nitrogen from wastewater processing, $4,000 to over $20,000/ton of nitrogen removed; and management practices to reduce nitrogen from fertilizers, animal waste, and other non-point sources, $1,000 to over $100,000/ton of nitrogen removed (see docket items IV–J–25 (Camacho, 1993:97–98) and IV–J–27 (Shulyer, 1995:6)).

TABLE 2.—AVERAGE COST-EFFECTIVE OF NO_X Controls by Source

[Utility, other point source, mobile]

	Range in typical cost-effectiveness ($/ton)	Percent reduction
Utility sources (Coal w/advanced NO_X controls):		
Wall-fired	$1,226–1,670	60–90
Tangentially-fired	1,439–1,935	60–90
Cyclones	440–880	60–90
Cell burners	624–801	60–80
Wet bottoms	572–733	60–90
Roof (vertically-fired)	750–907	60–90
Utility sources (Oil and Gas):		
Wall dual-fired	748–2,263	40–90
Tangential dual-fired	507–1,573	30–90

Source: Ozone Transport Assessment Group, Control Technologies and Options Workgroup, Final Report, April 11, 1996.

Title IV phase II NO_X rule	Average cost-effectiveness of § 407(b)(2) ($/ton)	Percent reduction under § 407(b)(2)
Group 1 and group 2	$229	20

See section IV.B (Table 17) of this preamble.

Non-utility point sources	Range in typical cost-effectiveness ($/ton)	Percent reduction
Non-utility boilers	$490–19,600	5–90
Process heaters	290–50,000	20–90
I.C. engines	180–13,400	5–98
Gas turbines	130–2,760	60–90
Residential fuel combustion	1,600–62,500	50–100
Cement manufacturing	470–4,870	20–90
Metals processing	120–11,600	12–96
Wood manufacturing	1,000–10,000+	0–60
Agriculture chemical manufacturing	76–715	44–99
Incineration	800–10,000	10–77

Source: Ozone Transport Assessment Group, Control Technologies and Options Workgroup, Final Report, April 11, 1996.

Mobile sources	Range in typical cost-effectiveness ($/ton)	Percent reduction
Light-duty (on highway)	$1,100–260,000	0.2–21
Heavy-duty (on highway)	1,000–40,000	0.02–5.6
Non-road	119–23,000	0.4–3.4

Source: Mobile Sources Assessment: NO_X and VOC Reduction Technologies for Application by the Ozone Transport Assessment Group, Final Report, March 4, 1996.

Title IV phase II NO_X rule	Average cost-effectiveness of § 407(b)(2) ($/ton)	Percent reduction under § 407(b)(2)
Group 1 and Group 2	$229	20

vii. Need to Revise Group 1 Limits and Establish Group 2 Limits

As discussed above, in order to mitigate adverse effects on health and the environment due to NO_X emissions, significant, additional reductions in regional atmospheric NO_X emissions from current levels are likely to be necessary. Further, the contribution of the final rule toward the overall NO_X reduction goal is approximately 5%. The NO_X reductions under the rule represent only a portion of the much larger NO_X reductions likely to be needed and are among the most cost-effective reductions available. EPA concludes that the reductions under the final rule represent a reasonable step toward achieving necessary NO_X reductions.

Some commenters suggested that, because the authority to revise the Phase II, Group 1 emission limitations and to issue Group 2 emission limitations arises under title IV of the Clean Air Act, EPA must consider only the acidification impacts of NO_X emissions in deciding whether to revise or issue limitations. Allegedly, all other impacts must be addressed only under other provisions of the Act. EPA rejects this crabbed view of its authority under section 407(b)(2) as having no basis in statutory language or logic. In granting EPA the authority to decide to revise the Phase II, Group 1 emission limitations, section 407(b)(2) only requires a determination of the availability of more effective LNB technology and does not bar consideration of non-acidic deposition impacts. Similarly, in requiring EPA to issue Group 2 emission limitations, section 407(b)(2) sets forth several criteria for setting the limitations but none of the criteria bars consideration of non-acidic deposition impacts. On the contrary, section 407(b)(2) has a general requirement that EPA take account of ''environmental impacts'' in setting Group 2 emission limitations. 42 U.S.C. 7651f(b)(2).

In the absence of a statutory bar on considering all environmental impacts of NO_X emissions and in light of the general purpose of the Clean Air Act to, *inter alia,* ''protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population'', it would be illogical for EPA to focus exclusively on acid deposition.[3] 42 U.S.C. 7401(b)(1). The latter approach would require EPA to regulate on a piecemeal basis and to blindly ignore a major part of the harmful effects of NO_X emissions when setting nationwide NO_X emission limits under title IV. In any event, EPA maintains that, even if the Agency were confined to considering only the acidic deposition effects, referred to above, of NO_X emissions, it would still conclude that additional NO_X reductions are necessary and that the emission limitations set forth in today's rule should be adopted.

Some commenters also noted that section 401(b) states that the purpose of title IV is to reduce acidic deposition through reduction of annual SO_2 emissions of ten million tons from 1980 levels ''and, in combination with other provisions of this Act, of nitrogen oxides emissions of approximately two million tons from 1980 emission levels, in the forty-eight contiguous States and the District of Columbia.'' 42 U.S.C. 7651(b). According to such commenters, because this goal is already met by the existing Phase II, Group 1 emission limitations (as well as by regulations under other parts of the Clean Air Act), there is no basis for revising the limitations. However, section 401(b) provides only general guidance concerning implementation of title IV and, in light of the imprecision of its language, does not—and was not intended to—impose an absolute limit on the amount of NO_X reductions that can be required under emission limitations promulgated under section 407.

In contrast to the SO_2 provisions of title IV, which set a nationwide cap on total tonnage of SO_2 emissions (i.e., 8.95 million tons starting in 2010), the NO_X provisions of title IV provide only for limits on the NO_X emitted per mmBtu of fuel burned. Even if the NO_X emission limitations are met, increased use of existing coal-fired and other

[3] Although, as discussed below, section 401(b) states that the general purpose of title IV is ''to reduce the adverse effects of acid deposition'', this provision should not be interpreted as barring consideration of other environmental impacts for purposes of setting emission limitations under section 407. 42 U.S.C. 7651(b). EPA's interpretation—which harmonizes sections 101(b)(1) (stating the general purposes of the Clean Air Act) and 401(b) (stating the general purposes of title IV)—is that, while the primary focus in promulgating regulations under title IV is reduction of acidic deposition, other environmental impacts may also be considered.

utility boilers in the future in response to growth in demand for electricity can result in increased tonnage of NO_X emissions. The NO_X emissions reductions projected to be achieved through adoption of any given set of NO_X emission limitations under title IV are therefore not permanent. For this reason, when EPA estimates NO_X reductions resulting from title IV emission limitations, the estimates are tied to a specific year, in this case the year 2000. *Regulatory Impact Analysis of NO_X Regulations* at 1–7 and 1–8, December 8, 1995. Moreover, as discussed above, total NO_X emissions are projected to decline through 2000, increase thereafter, and exceed the two million guideline by around 2006. In short, the commenters' claim that a two-million-ton emission reduction ''goal'' is ''satisfied'' by the existing Group 1 emission limitations is inaccurate because a two-million-ton level of reductions from 1980 achieved for a given year (e.g., for 2000) through these limitations is unlikely to be maintained, in the near future without further reductions.

Although EPA maintains that the 2 million ton guideline in Section 401(b) aims at total NO_X emissions of 2 million tons below the 1980 levels, EPA notes that the final rule will result in total Group 1 and Group 2 boiler NO_X emissions around 2 million tons less than what they otherwise would have been in 2000. The annual NO_X reductions anticipated from the existing Group 1 emission limitations under the April 13, 1995 rule and additional annual reductions anticipated from the Phase II, Group 1 and Group 2 emission limitations under today's final rule are about 1,170,000 tons and 890,000 tons respectively for the year 2000, for a total of about 2,060,000 tons. EPA's current estimate of reductions from the April 13, 1995 rule is lower than the reductions originally estimated (i.e., about 1,890,000 tons for the year 2000) for that rule. 59 FR 13538, 13562–63 (March 22, 1994); *see also* 59 FR 18760 (adopting for April 13, 1995 rule the Regulatory Impact Analysis originally promulgated for the March 22, 1994 rule).

In making the original estimates of reductions, EPA used emissions factors (i.e., estimated uncontrolled emission rates based on coal type and boiler type) to determine the uncontrolled emissions of boilers to which the existing Group 1 emission limitations were to be applied. In response to comment in today's rulemaking concerning the inaccuracy of emission factors, EPA has minimized its use of emission factors and instead relied almost exclusively on actual, short-term, uncontrolled emissions data from continuous emissions monitoring obtained during annual monitor certification testing (i.e., CREV data) or submissions of CEM, EPA reference method, or other test data by utilities. This data was not generally available to EPA when the April 13, 1995 rule was published.[4] As a result of using more accurate uncontrolled emissions data, EPA's estimates of anticipated reductions under the existing Group 1 emission limitations are now more accurate and are lower. Even if section 401(b) were viewed as imposing a ''ceiling'' of ''approximately two million tons'' of NO_X reductions under section 407, the reductions anticipated under the emission limitations adopted in the April 13, 1995 rule and today's final rule are consistent with that ''ceiling.''

For the reasons discussed above, EPA concludes that it should exercise its discretion under section 407(b)(2) to revise the Phase II, Group 1 emission limitations. The revised Group 1 limits represent a reasonable step toward achieving the significant NO_X reductions that are likely to be necessary, and are consistent with the 2 million ton guideline for NO_X reductions. The revision of the Group 1 emission limitations will result in about 120,000 tons of additional annual NO_X reductions. Actions to achieve NO_X reductions beyond those realized under title IV are being considered, or will be considered in the future, under other titles of the Clean Air Act.

Unlike the Group 1 limitation revisions, which are discretionary under section 407(b)(2), the issuance of Group 2 emission limitations is mandatory under that section so long as the requirements of the section (e.g., cost comparability) are met. However, as noted above, EPA is required, when setting Group 2 emission limitations under section 407(b)(2), to consider environmental impacts. EPA's application of the section 407(b)(2) requirements for setting Group 2 emission limitations—including the consideration of environmental impacts—is set forth in detail below in section III.B of this preamble. EPA concludes that, like the Group 1 revisions, the Group 2 emission limitations supported and adopted in that section of the preamble represent a reasonable step toward achievement of necessary, significant NO_X reductions and are consistent with the 2 million ton guideline for NO_X reductions.

[4] For the January 19, 1996 proposal in the instant rulemaking, EPA replaced many, but not all, of the emissions factors with actual data, which resulted in estimated annual reductions under the current Group 1 emission limitations of about 1,540,000 million tons. *See* Regulatory Impact Analysis for the proposed rule (docket item II–F–2).

II. Public Participation

Regulations were proposed in the Federal Register on January 19, 1996 (61 FR 1442). The notice invited public comments and copies of the proposed rule were made available to interested parties.

EPA held a public hearing to provide interested parties the opportunity for oral presentation of data, views, or arguments concerning the proposed regulations. The hearing was held on February 8, 1996 in Washington, DC. Four persons testified at the hearing concerning issues related to the proposed regulations. The hearing was open to the public, and each attendee was given an opportunity to comment on the proposed regulations. (See docket items IV–F–1, IV–F–2 and IV–F–3.) The initial public comment period (January 19, 1996 to March 4, 1996) was extended by two weeks to March 19, 1996 to allow additional time for inspection of interagency review materials which EPA added to the docket on January 26, 1996. (See docket item III–A–2.)

III. Summary of Major Comments and Responses

EPA received approximately 100 comment letters regarding the proposed regulations, presenting more than 200 issues. Commenters included public and municipal utilities, utility associations, state/local agencies and Attorneys General, environmental organizations, vendors, general industry, research/trade groups, and private citizens. A copy of each comment letter received is included in the rulemaking docket. A list of commenters, their affiliations, and the EPA docket item number assigned to their correspondence is included in the background information document.

All of the comments have been carefully considered, and where determined to be appropriate by the Administrator, changes have been made in the final regulations. The background information document includes a summary of all the comments and EPA's response on each of the relevant issues. The following sections of the preamble provide a summary of the major comments received and the Agency's response to those major comments.

A. Phase II, Group 1 Boiler NO_X Emission Limits

1. Boiler Population Used To Assess NO_X Emission Limits

Background. For the proposed rule, EPA developed a computerized boiler database containing detailed information on the characteristics and pre-retrofit and post-retrofit emission rates of coal-fired units with Group 1 boilers on which low NO_X burners (LNBs) had been installed without any other NO_X controls (''the LNB Application Database''). This database contained all known applications of LNBs to Group 1 boilers that were installed subsequent to 11/15/90 (the date of enactment of the 1990 amendments to the CAA) and for which EPA had at least 52 days of quality assured post-retrofit data measured by continuous emission monitors (CEMs) certified according to 40 CFR part 75. The 24 wall-fired boilers and 9 tangentially fired boilers in this database formed the empirical basis for EPA's assessment of the effectiveness of low NO_X burner technology and the revised annual NO_X emission limitations provisions for Group 1 boilers in the proposed rule.

Comment/Analyses: EPA received approximately 25 comment letters (from 19 utilities, 3 utility associations, 2 states, and an environmental organization) on the appropriateness of including or excluding certain boilers and the selection criteria used to define eligibility for the LNB Application Database.

Several commenters suggested that EPA include specific boilers to increase the size and improve the representativeness of the tangentially fired subset in the LNB Application Database: Riverbend 7 and 8, Allen 1 and 3, J.H. Campbell 3, Gallatin 4, and Lansing Smith 2 (see, for example, docket items IV–D–22, p. 1; IV–D–21, pp. 2–3; IV–D–20, pp. 7–9, and IV–D–65, p. 22). The commenters acknowledged that many of these retrofit cases did not satisfy the quality assurance criteria that EPA had established for inclusion in the LNB Application Database. They believed, however, that the general benefits of broadening the experiential basis for tangentially fired boilers outweighed specific data quality concerns. As one commenter said, ''Although not [based on] CEM data, Gallatin Unit 4's performance test result of 0.47 lb/10^6 Btu is reliable, relevant evidence * * * and should be considered by EPA.'' (See docket item IV–D–20, p. 9.)

Commenters also suggested that EPA include specific boilers to improve the representativeness of the wall-fired subset in the LNB Application Database, particularly with respect to boilers with high uncontrolled emission rates: Hammond 4, Watson 4 and 5, Valley 1 and 2 (see, for example, docket items IV–D–65, p.22). Several commenters cited additional wall-fired retrofit cases within the context of the related issue of the dependence of NO_X emissions on boiler load: Conesville 3, Picway 9, Amos 1 and 2, Big Sandy 2, Glen Lyn 6, Colbert 5, Valley 1–4; Presque Isle 5 and 6 (see docket items IV–D–73, p.1; IV–D–20, p.5; IV–D–26, p.2).

On the other hand, several commenters fully endorsed the quality assurance criteria EPA has used to determine eligibility for the LNB Application Database (see, for example, docket items IV–D–063, p.12; IV–D–046, p.3–4). They said that EPA properly excluded older LNB installations (such as Gallatin 4, Lansing Smith 2, and Hammond 4) for which quality assured long-term post-retrofit CEM data did not exist. (EPA notes that this criterion generally excludes experimental or otherwise short-lived LNB installations such as those used for technology demonstrations, and the Allen units.[5]) These commenters also recommended that EPA should attach greater significance to (or rely exclusively on) LNB applications in the 13-state Northeast Ozone Transport Region (OTR) for the evaluation of LNB technology effectiveness because these applications have been required to meet a NO_X emission limit beginning May 31, 1995, whereas most other applications have not had to comply with a recently established NO_X standard.

Some commenters correctly noted that one wall-fired boiler in the LNB Application Database used for the proposed rule analysis, North Valmy 1, should be excluded because this boiler had pre-existing NO_X controls (i.e., Babcock and Wilcox (B&W) DRB version LNBs) so its baseline measurement does not represent an uncontrolled emission rate. EPA notes that this NSPS boiler, when retrofitted with modern LNBs (i.e., B&W XCL version), has sustained an average post-retrofit controlled emission rate of 0.264 for calendar year 1995 (see docket item II–A–9). ''NSPS boilers'' are new coal-fired utility units on which construction commenced after August 17, 1971, which are subject to New Source Performance Standards (NSPS) (40 CFR part 60, subparts D or Da). Some NSPS boilers had early versions of LNBs and/or some other type of NO_X combustion control installed as original equipment. EPA has excluded these ''controlled NSPS boilers'' from the LNB Application Database and regression models because their measured baseline emission rates do not generally represent uncontrolled emissions. EPA has included all NSPS boilers, both controlled and those without built-in NO_X combustion control equipment, in the Phase II, Group 1 boiler set to which the models are applied since NSPS boilers represent approximately one third of the units affected by this rulemaking.

One commenter recommended that EPA exclude two boilers, Coleman C1 and Pulliam 7, because, according to this commenter, these boilers have low NO_X combustion controls beyond the LNB definition in 40 CFR 76.2. EPA disagrees with this commenter's opinion that these two retrofits include auxiliary combustion air outside the waterwall hole which are '' 'staging' combustion on active burners analogous to overfire air'' (see docket item IV–D–51, p. 9). EPA also notes that another commenter, who represents 67 utilities, included both units in their regression analyses on the performance of LNBs applied to wall-fired Group 1 boilers (see docket item IV–D–65, p. 58 and Enclosure 8, Table 4–1). DOE included Coleman C1 in its regression analyses, but excluded Pulliam 8 (probably because, as EPA learned after the rule proposal, the utility switched to Powder River Basin coal for both Pulliam 7 and 8) (see docket item II–D–62).

Some commenters recommended that EPA include Group 1 boilers that installed both LNB and overfire air (OFA) in the LNB Application Database, primarily because they believe units with high uncontrolled emission rates were under-represented in the proposed rule analysis (see, for example, docket item IV–D–58, p. 4). These commenters provided supporting data for certain boilers, including: Eastlake 1, 3, and 4; and Ashtabula 7 (see docket item IV–D–23, p. 5). As discussed later in this section of the preamble, EPA disagrees with this recommendation. First, OFA cannot be considered in determining whether to revise the Group 1 limits and the assessment of the achievable performance of LNBs alone is problematic when LNBs are used in combination with other technologies. Further, the addition of 20 units to the LNB Application Database has

[5] The Allen plant is located in Gaston County, NC, which, until July 1995, was considered in non-attainment for ozone. The utility installed LNBs on two Allen boilers, the vendor is reported to have optimized in mid 1995. In July 1995, Gaston County was redesignated to ozone attainment and low NO_X operation was discontinued on Allen 1 and 3 on September 1, 1995 (see docket item IV–D–22, p. 1). As a result, Allen units 1 and 3 each have less than 52 days of emissions data after optimization of their respective LNBs.

significantly improved the robustness of EPA's regression models for units with high uncontrolled emission rates.

Several commenters agreed with EPA's decision to exclude boilers using Powder River Basin or other subbituminous coal from the LNB Application Database (see, for example, docket items IV–D–15, p. 3; IV–D–65, p. 20). For such boilers, measured post-retrofit NO_X emission reductions reflect the combined effects of switching to a coal with inherently lower NO_X emissions plus the application of LNBs.

Response: In light of the comments requesting the inclusion and/or exclusion of specific boilers from the LNB Application Database, EPA has formalized and expanded the data quality assurance criteria used in the rule proposal into Data Quality Objectives (DQOs). The DQOs are rigorous and precisely defined rule tables which were used to screen all candidate boiler retrofit cases and hourly CEM data observations. The DQOs are designed to ensure that the LNB Application Database satisfies objective and consistent data quality assurance standards. Table 3 presents EPA's DQOs for evaluating candidate boiler retrofit cases (DQOs Applied to Boilers) and for quality assuring hourly post-retrofit CEM data (DQOs Applied to Data).

TABLE 3.—DATA QUALITY OBJECTIVES APPLIED TO BOILERS AND DATA TO SCREEN BOILERS FOR INCLUSION IN THE LNB APPLICATION DATABASE

DQO#	DQOs applied to boilers	Rationale
1B	Only dry bottom wall-fired and tangentially fired boilers will be included in the database.	NO_X emission rates for Group 1 boilers affect dry bottom wall-fired and tangentially fired boilers only.
2B	Boilers must have an installed LNB control technology only. Boilers with LNB plus overfire air (OFA) or other controls will not be included in the database. This determination is made by either (1) information in EPA's Program Tracking System Database or (2) direct contact with individual utilities.	Consistent with *Alabama Power v. EPA,* 40 F.3d 450 (D.C. Cir. 1994), EPA cannot consider LNB+OFA installations when setting Group 1 limits.
3B	Any boiler with an LNB installation date prior to November 15, 1990 will not be included in the database. LNB installation dates are determined from (1) EPA's Program Tracking System Database, (2) estimation of the dates from visual interpretation of hourly emissions plots, or (3) direct contact with the utilities.	Revised Group 1 limits are to be based on improved performance of LNBs installed after passage of 1990 Clean Air Act Amendments (CAAA).
4B	Only boilers with at least 52 days of post-retrofit data, following an equipment ''break-in'' period of 30 calendar days, will be included in the database.	52 days is generally accepted as the minimum time period for assessing long-term performance of NO_X combustion control technology (see preamble section III.A.2.ii). Vendors and utilities acknowledge existence of ''break-in'' period, lasting about 30 calendar days, during which boiler operations are often highly irregular.
5B	Boilers for which LNB design, installation and/or operations are known to be seriously flawed will be excluded from the database. This determination will be made on the basis of published utility papers or information submitted to EPA for a rulemaking docket. (This DQO, however, was never used as the sole basis for rejecting any candidate boiler retrofit cases from current database.).	Boilers with serious and persistent LNB design, installation, and operational flaws do not reflect the true NO_X emission reduction associated with LNB retrofit. (This DQO is a logical extension of a pertinent statutory concept. Section 407(d) requires selection of appropriate control equipment ''designed to meet the applicable emission rate'' as well as proper installation and operation of such equipment for determining eligibility, and an appropriate emission rate, for an alternative emission limitation).
6B	Boilers must have a pre-retrofit uncontrolled emission rate based on quality assured short-term CEM or test data that is verifiable in the CREV database, the Acid Rain Cost Form for NO_X Control Costs, or another source available to EPA.	Quality assured short-term uncontrolled emission rate data are needed to perform consistent analysis and projections using first and second parts of model (see preamble, section III.A.3.ii.).
7B	Quarterly report submissions for boilers must pass the quality assurance (QA) criteria in 40 CFR part 75.	Quarterly report submissions that do not satisfy the CEM and other QA criteria in 40 CFR part 75 contain insufficient information to verify the accuracy of reported NO_X emission rate data.
8B	NSPS boilers are excluded from the database	Pre-NSPS boilers differ from NSPS boilers with regard to furnace volume and heat release rates and, as a result, NSPS units can more easily meet a NO_X reduction target by retrofitting LNBs. This makes NSPS units unrepresentative for establishing overall LNB NO_X reduction efficiency.
9B	Only boilers not using Powder River Basin coal will be included in the database.	Powder River Basin coal has been identified by utilities as a subbituminous coal which produces very low NO_X emission rates. Its performance cannot necessarily be reproduced by any other type of coal for LNB applications.
DQO#	**DQOs applied to data**	**Rationale**
1D	Data generated using EPA's missing data substitution procedures will not be used (40 CFR part 75).	The missing data routines include a penalty for not properly maintaining CEM equipment. In order to assess actual LNB performance, only measured NO_X emission rate data will be used.
2D	Hourly emission rate data will be adjusted using the appropriate bias adjustment factor for the boiler.	Using bias adjusted NO_X emission rates will ensure compatibility of CEM NO_X emission rate measurements obtained from different monitors.

TABLE 3.—DATA QUALITY OBJECTIVES APPLIED TO BOILERS AND DATA TO SCREEN BOILERS FOR INCLUSION IN THE LNB APPLICATION DATABASE—Continued

DQO#	DQOs applied to boilers	Rationale
3D	NO_X emission rates greater than 10 lb/mmBtu and less than or equal to 0 lb/mmBtu will be discarded.	Such reported data values are clearly erroneous (i.e., physically impossible) and, thus, should not be included when estimating achievable emission rates.
4D	Hourly emission rate data for ''break-in'' period, defined as the 30 calendar days following estimated date the boiler began operating after shutdown for LNB retrofit (denoted on tables as ''LNB retrofit date''), will be discarded.	Vendors and utilities acknowledge existence of ''break-in'' period, lasting about 30 calendar days, during which boiler operations are atypical due to vendor performance guarantee testing. Discarding hourly emissions data for ''break-in'' period also allows for any uncertainty associated with exact date of beginning of post-retrofit period.

EPA applied these DQOs to candidate boilers: those used in the Phase II proposed rule analysis (Tables 2 and 3, 61 FR 1442, 1446–1447, January 19, 1996); those that commenters requested EPA to consider (many of which are named above); and additional LNB boiler applications which EPA identified using 1995 and first and second quarter, 1996 CEM data submitted pursuant to 40 CFR part 75 and other program information. A detailed presentation of the results of EPA's comprehensive data evaluation appears in docket item IV-A–6. The resulting LNB Application Database, presented in Tables 4 and 5, consists of 39 wall-fired boilers and 14 tangentially fired boilers and contains over 477,800 hours of quality assured post-retrofit CEM data on LNB performance.

TABLE 4.—WALL-FIRED BOILERS IN THE LNB APPLICATION DATABASE

Obs. No.	ORISPL	Unit name/unit ID	Phase	Uncontrolled No_X rate (ln/mmBtu)	Load weighted post-optimization No_X rate (ln/mmBtu)	Percent No_X removal
1.	26	Gaston unit 1	1	0.900	0.384	57.3
2.	26	Gaston unit 2	1	0.780	0.384	50.8
3.	26	Gaston unit 3	1	0.800	0.413	48.4
4.	26	Gaston unit 4	1	0.800	0.413	48.4
5.	47	Colbert unit 1	1	0.800	0.421	47.4
6.	47	Colbert unit 2	1	0.670	0.421	37.2
7.	47	Colbert unit 3	1	0.830	0.421	49.3
8.	47	Colbert unit 4	1	0.860	0.421	51.0
9.	47	Colbert unit 5	1	0.780	0.434	44.4
10.	641	Crist unit 6	1	1.040	0.492	52.7
11.	641	Crist unit 7	1	1.160	0.517	55.4
12.	856	Edwards unit 2	2	1.000	0.514	48.6
13.	1043	Ratts unit 1SG1	1	1.080	0.508	53.0
14.	1043	Ratts unit 2SG1	1	1.090	0.468	57.1
15.	1295	Quindaro unit 2	1	0.635	0.405	36.2
16.	1355	Brown unit 1	1	1.000	0.495	50.5
17.	1357	Green River unit 5	1	0.836	0.400	52.2
18.	1381	Coleman unit 1	1	1.410	0.489	65.3
19.	1381	Coleman unit 2	1	1.290	0.466	63.9
20.	1384	Cooper unit 1	1	0.900	0.419	53.4
21.	1384	Cooper unit 2	1	0.900	0.419	53.4
22.	2049	Watson unit 4	1	1.100	0.413	62.5
23.	2049	Watson unit 5	1	1.220	0.431	64.7
24.	2629	Lovett unit 4	2	0.570	0.349	38.8
25.	2629	Lovett unit 5	2	0.585	0.329	43.8
26.	2840	Conesville unit 3	1	0.852	0.412	51.6
27.	2843	Picway unit 9	1	0.866	0.415	52.1
28.	3131	Shawville unit 1	1	0.990	0.486	50.9
29.	3131	Shawville unit 2	1	1.020	0.483	52.6
30.	3159	Cromby unit 1	2	0.600	0.378	37.0
31.	3178	Armstrong unit 2	1	1.042	0.420	59.7
32.	3948	Mitchell unit 1	1	0.999	0.500	50.0
33.	3948	Mitchell unit 2	1	0.999	0.500	50.0
34.	4042	Valley unit 1	1	1.100	0.477	56.6
35.	4042	Valley unit 2	1	1.100	0.477	56.6
36.	4042	Valley unit 3	1	1.050	0.473	55.0
37.	4042	Valley unit 4	1	0.925	0.473	48.9
38.	6041	Spurlock unit 1	1	0.900	0.414	54.0
39.	6085	RM Schahfer unit 15	2	0.420	0.228	45.7

TABLE 5.—TANGENTIALLY FIRED BOILERS IN THE LNB APPLICATION DATABASE

Obs. No.	ORISPL	Unit name/unit ID	Phase	Uncontrolled NO_X rate (ln/mmBtu)	Load weighted post-optimization NO_X rate (ln/mmBtu)	Percent NO_X removal
1.	710	McDonough unit 1	1	0.657	0.388	40.9
2.	710	McDonough unit 2	1	0.600	0.388	35.3
3.	728	Yates unit Y4BR	1	0.561	0.421	25.0
4.	728	Yates unit Y5BR	1	0.650	0.421	35.2
5.	1374	Elmer Smith unit 2	1	0.859	0.419	51.2
6.	1710	Campbell unit 1	1	0.690	0.456	33.9
7.	2554	Dunkirk unit 1	2	0.478	0.343	28.2
8.	2554	Dunkirk unit 2	2	0.478	0.331	30.8
9.	2642	Rochester 7 unit 4	2	0.587	0.365	37.8
10.	2732	Riverbend unit 7	2	0.580	0.421	27.4
11.	2732	Riverbend unit 8	2	0.640	0.383	40.2
12.	2732	Riverbend unit 10	2	0.772	0.357	53.8
13.	4041	S. Oak Creek unit 7	1	0.661	0.377	43.0
14.	4041	S. Oak Creek unit 8	1	0.665	0.377	43.3

The Agency believes that the addition of 20 units to the LNB Application Database increases the overall representativeness of the database for use in analyzing the achievable emission rates for Group 1 boilers and addresses commenters'' concerns that the original database may not adequately represent units with high uncontrolled emission rates. The current database contains 22 units with uncontrolled emission rates above the rates classified by one utility commenter as ''high'' (i.e., for wall-fired boilers, above 0.90 lb/mmBtu and for tangentially fired boilers, above 0.68 lb/mmBtu, see docket item IV–G–16, p. 7). For several reasons, the Agency believes these additions to the database are more appropriate than adding boilers with LNB and overfire air (OFA) as suggested by some commenters. First, under the ruling in *Alabama Power* v. *EPA,* 40 F.3d 450 (D.C. Cir. 1994), EPA cannot consider LNB with OFA installations in the LNB Application Database for setting Group 1 limits. Second, isolating the true NO_X reduction performance of the LNB portion of LNB+OFA systems is problematic because the controls are designed to reduce NO_X as an integrated system and site-specific factors influence the relative contribution that each component (LNB vs. OFA) is designed to achieve. Further, there is no basis for assuming that the performance of the LNB portion, even if this could be measured accurately, is representative of the performance that could be achieved by LNBs without the addition of OFA.

2. Time Period/Averaging Basis Used To Evaluate Performance of Low NO_X Burner Technology

i. Background

Because the Acid Rain Phase I NO_X Emission Reduction Program did not go into effect until January 1, 1996, EPA did not have, at the time the proposed rule was issued, CEM data on the performance of LNBs applied to Group 1 boilers during a period when affected boilers were required to meet the annual Phase I NO_X emission limitations. Further, for the reasons discussed below, it could not be assumed that all the CEM data available, some of which had been recorded as early as January 1, 1994, reflected LNB performance during optimized NO_X removal conditions.

As discussed in the Regulatory Impact Analysis (RIA) for the proposed rule (see docket item II–F–2), plants incur both fixed and variable operation and maintenance (O & M) costs when operating LNBs to reduce NO_X emissions to the lowest practicable level consistent with prudent boiler operations to comply with regulatory emission limitations. Therefore, even though LNB controls are installed, utilities have a financial incentive not to operate units throughout an extended period of pre-compliance to sustain the emission reductions the controls were designed to achieve, since this would increase O & M costs when the NO_X emission reductions are not yet required. Thus, the average NO_X emission rate measured over an extended pre-compliance period may not be a good predictor of 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.

EPA's objective, then, was to identify the time period in the stream of post-retrofit hourly CEM data that corresponds to operation under optimized NO_X removal conditions. EPA believed this time period should contain 52 days of valid CEM data since, in publications and in past rulemakings, the Department of Energy (DOE) and the utility industry have stated that acceptable results of long-term performance require 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 defined a 52-day ''low NO_X period'' for the purposes of assessing performance of LNBs applied to Group 1 boilers in the proposed rule. The ''low NO_X period'' was determined by identifying the lowest average NO_X emission rate each boiler has sustained for at least 52 days, i.e., over a period of 1,248 hours when the boiler was operating and valid CEM data (measured by CEMS certified pursuant to 40 CFR part 75) were available. The low NO_X period for most boilers is considerably longer than 52 calendar days since hours during which the boiler did not operate or hours for which valid CEM data were not recorded are ignored and do not count towards the required total of 1,248 hours.

Even prior to the proposed rule, utility commenters and DOE had expressed the concern that by not using essentially all the recorded by post-retrofit CEM data, EPA was not accurately assessing the long-term performance capabilities of LNBs (61 FR 1442).[6] Further, these commenters believed that using a fixed-length shakedown period of 30 to 90 days, applied universally to all installations, to allow for optimizing LNBs and operator training was more objective than using the variable-length and site-specific shakedown periods implicit in EPA's low NO_X period methodology. Accordingly, for the proposed rule, EPA also developed estimates of post-retrofit average NO_X emission rates for another time period beginning 30 calendar days after the estimated date the boiler began operating after shutdown for LNB installation and continuing to the end of the CEM data set. This period is referred to as the ''overall post-retrofit period'' in the proposed rule (61 FR 1447 (Tables 4 and 5); also see docket item II–A–9, Table 2) and as the ''post-retrofit minus 30 days period'' (abbreviated as ''30-day post-retrofit period'' in tabular column headings) in the technical support document for the final rule (see docket item IV–A–6).

For the proposed rule, EPA developed estimates of post-retrofit average NO_X emission rates for a third period which, like the overall post-retrofit period, uses most of the recorded post-retrofit CEM data and, like the low NO_X period, allows for a variable-length shakedown period to accommodate the site-specific nature of LNB equipment optimization and operator training processes. This time period begins with the first hour of the low NO_X period and continues to the end of the CEM data set. It is referred to as the ''post-optimization period'' in both the proposed rule and final rule analyses. As mentioned previously in section B of this preamble, the post-optimization period forms the basis for EPA's final assessment of the effectiveness of LNBs applied to Group 1 boilers.

Another concern, which was raised prior to the proposed rule by utility commenters and DOE, is that limited time periods such as the low NO_X period may not adequately capture annual dispatch patterns and seasonal variations in demand for electrical power generation. Accordingly, for the proposed rule, EPA also investigated the representativeness of load dispatch during the low NO_X period by comparing it to the load dispatch during calendar year 1994 for each boiler or common stack in the LNB Application Database. EPA developed two histograms using ''load bins'' for the horizontal axis: (1) Average hourly NO_X emission rate as a function of load during the low NO_X period; and (2) frequency of various boiler operating loads throughout 1994 (for which EPA had actual performance data from the CEM data set). Then, EPA used these histograms to estimate ''load-weighted annual average 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 the boiler operated in that load bin during 1994 (61 FR 1448 (Tables 6 and 7)). To test the representativeness of boiler operations during the low NO_X period, EPA also created bar charts comparing the percentage of time a boiler operated in each load bin during the low NO_X period to the percentage of time it operated in that load bin during calendar year 1994 (see docket item II–A–9, Appendix B). Using these graphical analyses, EPA concluded that most boilers in the LNB Application Database had a load dispatch pattern during their low NO_X period similar to their annual dispatch pattern in 1994.

When analyzing long-term post-retrofit CEM data for the proposed rule, EPA found no strong correlation between boiler operating loads and hourly average NO_X emission rates for either wall-fired boilers or tangentially fired boilers in the LNB Application Database. While earlier technical analyses performed for EPA in support of other utility NO_X emission rulemakings had generally adopted the industry accepted presumption of a NO_X vs. boiler load relationship for many uncontrolled Group 1 boilers, they also showed the direction, magnitude, and form of this correlation to be both highly boiler-specific and difficult to predict (see, for example, docket item IV–J–20).

Nevertheless, EPA recognized that a predictable systematic correlation between hourly average NO_X emission rates and boiler load for all or some boilers could have significant ramifications for proper application of a 52-day low NO_X period methodology. Accordingly, EPA developed the ''load-weighted annual average NO_X emission rates,'' defined above, to account for the potential existence of a NO_X vs. boiler load relationship. Because the load-weighted annual average NO_X emission rates were essentially the same as or lower than the average NO_X emission rates for the low NO_X period for these boilers (see 61 FR 1446 (Tables 5 and 6)) EPA selected the simpler form, a straight average over the low NO_X period, as the basis for the proposed rule.

The Agency received many detailed comments and supporting data about the appropriateness of using a limited low NO_X period for assessing LNB performance, the merits of site-specific variable-length vs. universal fixed-length shakedown periods to reflect LNB equipment optimization and operator training, the advantages and disadvantages of the alternative time periods EPA had considered for the proposed rule analysis, and the technical issue of the existence of a NO_X vs. load relationship and its relevance for assessing LNB performance applied to Group 1 boilers. The first three issues are discussed in the next section within the context of the low NO_X period methodology whereas the last issue, for which EPA received approximately 25 site-specific data submissions from utility boiler owners or operators, is treated separately in the subsequent section.

ii. Use of 52-Day Low NO_X Period

Comment/Analyses: EPA received approximately 29 comment letters (from 22 utilities, 2 utility associations, 3 states, a gas industry representative, and an environmental association) on the appropriateness of using a 52-day low NO_X period for assessing LNB performance when, for some boilers, considerably more post-retrofit data was available.

Some commenters fully endorsed EPA's 52-day methodology and implicit assumption that utilities not under a compliance obligation are unlikely to operate the controls for maximum emission reductions following LNB optimization and a low NO_X test period. They believed EPA had demonstrated that the 52-day methodology and ''load-weighted annual average NO_X emission rates'' adequately addressed annual dispatch and load patterns in most cases. A utility that owns and operates coal-fired units which have become subject to state-mandated NO_X Reasonably Available Control Technology (RACT) requirements in 1995 said EPA should go even further and ''use NO_X data only from units that have had to comply with a recent NO_X standard (such as NO_X RACT)'' for

[6] EPA notes that the tangentially fired boilers in the LNB Application Database used for the proposed rule had little more than the requisite 52 days of quality assured post-retrofit CEM data. Only CEM data reported through June 30, 1995, the end of the second quarter reporting period, were available for analysis and the LNB retrofit dates for tangentially fired boilers occurred in late 1994 or early 1995.

evaluating the effectiveness of LNB technology (see docket item IV–G–14, p. 1). EPA notes that 6 wall-fired boilers and 3 tangentially fired boilers in the LNB Application Database are located in the Northeast Ozone Transport Region and are subject to NO_X RACT requirements. The mean load-weighted annual average NO_X emission rates over the post-optimization period for these boilers are: 0.403 lb/mmBtu (wall-fired) and 0.344 lb/mmBtu (tangentially fired).

One commenter noted that utilities had an explicit disincentive for operating their LNBs to achieve the maximum practicable emission reductions during 1994 and 1995, since section 407(b)(2) allows EPA to promulgate revisions to Group 1 emission standards if measured average post-retrofit NO_X emission rates during this time frame indicate ''more effective low NO_X burner technology is available'' (see docket item IV–D–63, p.14). Another commenter endorsed the conclusion that observations during the 52-day low NO_X period may understate the actual reduction capability of LNBs (see docket items IV–D–047, p. 2 and IV–D–063, p. 12–14).

Other commenters disagreed with the assumption that utilities did not have any incentive to operate the installed LNBs to achieve maximum emission reductions consistent with prudent boiler operations. One utility stated that plant personnel ''operated [their] NO_X control systems in a compliance mode even though its units were technically not yet subject to the Phase I NO_X standard. [The utility] established performance goals based on operating NO_X reductions systems to meet the standard and management bonuses were geared to meeting these goals'' (see docket item IV–D–020, p. 6). EPA notes that all of this utility's wall-fired units sustained average NO_X emission rates below 0.44 lb/mmBtu throughout their ''post-optimization'' periods (i.e., the post-retrofit period excluding a shakedown period based on actual boiler experience). The post-optimization periods for these units varied in length from 12 to 18 months. Another utility stated that boilers were operated in a manner to optimize NO_X emission reduction; to do otherwise would be ''counterproductive to the design of the burners and would defeat the training of the operating staff'' (see docket item lV–D–023, p. 4). EPA notes that the units owned and operated by both of these utility commenters are located outside designated ozone nonattainment areas and are not subject to NO_X RACT or any other state-mandated NO_X control requirements. Their decision to operate in a low-NO_X mode, therefore, was voluntary and not made on the basis of whether a compliance obligation existed.

Several commenters indicated that the best approach for estimating annual average NO_X emission rates is to use a full year of post-retrofit monitoring data (see, for example, docket item IV–D–38, p. 3). Commenters reiterated the concern raised prior to the proposal rule, that by not using essentially all the recorded post-retrofit CEM data, EPA is not accurately assessing the long-term performance capabilities of LNBs (see, for example, docket items IV–D–35, p. 3; IV–G–15, pp. 2–3). They said EPA's 52-day low NO_X period methodology fails to take into account all of the operating variables that affect LNB performance and biases the LNB performance assessment toward emission reduction levels that may not be achievable over the long term. Further, commenters who participated in DOE Clean Coal Technology Demonstrations where the 52-day methodology was used, said the ''52-day rule'' defines ''the *minimum* number of continuous days of data needed before a data set can be considered 'long-term' data. It is not a rule that justifies selective editing of data, when more data are available'' (see docket item II–D–65, p. 29).

Some of these commenters suggested using all CEM data recorded after a fixed-length shakedown period whereas others believed a variable-length shakedown period is more appropriate given the site-specific nature of the LNB equipment optimization and operator training processes. EPA notes that one utility commenter reported that burner optimization for each of their five tangentially fired retrofits was completed within 120 days of startup (see docket item IV–D–23, p.4), which is considerably longer than the fixed 30-day shakedown period recommended by DOE and others. Another utility commenter reported that one of their wall-fired boilers, E.D. Edwards 2, was still being optimized more than a year after the retrofit date (see docket item IV–D–73, p. 3).

Several commenters indicated support for the post-optimization period approach, which EPA had presented in the proposed rule together with the 52-day low NO_X period methodology and load-weighted annual average NO_X emission rates. As one utility said, 'the post-optimization period' emission results are the best data set characterizing long-term low-NO_X mode boiler operation. This database maximizes the amount of low-NO_X mode data (i.e., sample size) collected following a period of demonstrated minimum NO_X operation.'' (See docket item IV–D–051, p. 8.)

Some commenters indicated a 52-day low NO_X period methodology would be credible for assessing the long-term performance of LNB technology if NO_X emission rates following LNB optimization do not vary significantly with boiler load (see, for example, docket item IV–D–72, p. 4). While these commenters generally believe NO_X emission rates are a function of load for many boilers (see discussion below under NO_X vs. Boiler Load Relationship), they do endorse the concept of using less than essentially all the recorded post-retrofit CEM data for assessing LNB performance.

Response: EPA believes that the 52-day low NO_X period methodology is technically justified for evaluating the achievable NO_X reduction capability of LNBs. This time period is sufficiently long, in most instances, to reflect long-term operation as evidenced by the generally similar load dispatch patterns observed during the low NO_X period and for calendar year 1994 for most boilers in the LNB Application Database. However, assuring proper selection of a low NO_X period that is representative of long-term boiler operating conditions in all instances can be difficult. An example of this is E.D. Edwards 2 where, according to the utility, the 52-day low NO_X period EPA had selected for the proposed rule analysis was atypical because it represents ''a period of testing in a low NO_X mode when the boiler was not optimized.'' Shortly thereafter, the utility re-tuned the boiler for improved efficiency, to reduce loss on ignition (LOI), and to maintain full compliance with particulate and opacity emissions standards. (See docket item IV–D–073, pp. 3–4.) Another commenter suggested possible adverse plant impacts may have occurred during the low NO_X period for a few other boilers in the LNB Application Database (see docket item IV–D–65, Enclosures 7 and 14); EPA's analysis of the specific impacts and remedial actions cited indicates that these possible issues are adequately addressed by extending the low NO_X period into the longer post-optimization period. Therefore, to maximize the likelihood that the performance evaluation period is representative and to assure observations over the broadest possible range of boiler operating variables and electric power generation demand scenarios, EPA is using the longer post-optimization period as the basis for assessing the performance of LNBs applied to Group 1 boilers for the final rule.

EPA's decision to use the post-optimization period is also based, in part, on the comments utilities have submitted regarding their actions to operate installed LNBs in a compliance mode during 1995, prior to the effective date of the Acid Rain Phase I NO_X Emission Reduction Program. EPA believes that there were reasons for utilities to operate installed LNBs as if the emission standards were in effect, even though such operation could increase utility O & M costs. EPA has rejected the concept of using a ''post-retrofit minus 30 (or 60 or 90) days period'' approach because utilities submitted significant evidence documenting that the time required for LNB optimization is highly variable and can be much longer than any of the fixed shakedown periods under consideration (see, for example, docket items IV–D–023, IV–D–073, and IV–G–04). Nonetheless, for comparison purposes, EPA has computed average NO_X emission rates based on the post-retrofit minus 30 days period for boilers in the LNB Application Database (see docket item IV–A–6, Table 3–1).

The addition of four more quarters of CEM data to the LNB Application Database substantially lengthens the post-optimization period for most boilers.[7] The post-optimization period also includes six months of 1996 compliance data for each Phase I boiler in the database. Table 6 presents summary statistics on the amount of hourly CEM data and calendar months encompassed by the post-optimization periods.

TABLE 6.—LNB APPLICATION DATABASE: HOURS OF CEM DATA AND CALENDAR MONTHS IN POST-OPTIMIZATION PERIODS

Boiler types	Hours of CEM data	Calendar months
Wall-fired boilers: 85% have at least 11 months of CEM data in post-optimization period:		
Range	3,877–15,829	6–30
Average	9,547	16
Total	372,324	610
Tangentially fired boilers: 79% have at least 11 months of CEM data in post-optimization period:		
Range	1,280–12,327	4–18
Average	7,537	14
Total	105,523	190

[7] A notable exception is the post-optimization time period for E.D. Edwards 2, which has been lengthened by a lesser amount. In response to the utility's comments, EPA has selected another low NO_X period, beginning after October 1, 1995, the date on which EPA believes corrections for adverse opacity and particulate emissions were substantially complete.

iii. NO_X vs. Boiler Load Relationship

Comment/Analyses: EPA received approximately 23 comment letters (from 21 utilities and 2 utility associations) criticizing EPA's decision in the proposed rule to base revised Group 1 emission limitations on a time period and averaging method which do not explicitly recognize the existence of a NO_X vs. load relationship. As mentioned previously under section III.A.2.i. of this preamble, EPA found no strong correlation between boiler operating loads and hourly average NO_X emission rates for either wall-fired boilers or tangentially fired boilers in the LNB Application Database when analyzing long-term post-retrofit CEM data for the proposed rule. Nevertheless, to test the potential impact of a NO_X/load relationship, in the analysis accompanying the proposed rule EPA developed a methodology that assumed the existence of a functional relationship between NO_X and boiler load. EPA then used this methodology to estimate ''load-weighted annual average NO_X emission rates'' for each boiler or common stack in the LNB Application Database (see docket item II–A–9, pp. 9–10).

The load-weighting methodology produced a weighted average based on the frequency of various operating load intervals (or ''bins'') during calendar year 1994 as reported in the CEM data set and the mean hourly NO_X emission rates for each load bin observed during the low NO_X period. (The computational procedures EPA used to estimate load-weighted annual average NO_X emission rates for the proposed rule are described under preamble section III.A.2.i.) Finding that the load-weighted annual average NO_X emission rates for these boilers were essentially the same as or lower than the average NO_X emission rates for the low NO_X period without the assumption of a NO_X/load relationship (see 61 FR 1446 (Tables 5 and 6)), EPA believed it was not necessary to investigate the NO_X vs. load relationship further and selected the more conservative (i.e., higher) of the two sets of estimates for modeling annual average emission rates that could be sustained by LNBs installed on Phase II, Group 1 boilers.

The commenters who criticized EPA's treatment of the NO_X/load relationship raised the following main issues:

Lack of statistical measures to quantify the extent of the NO_X/load relationship: Several commenters indicated that a critical missing link in EPA's analysis of this issue for the proposed rule was the failure to develop any statistical measures describing the strength of the association, if any, between NO_X and boiler load. As one utility said, EPA concluded ''through observance of the data'' that the relationship between NO_X and load is not strong for wall-fired boilers (see docket item IV–D–023, p. 5)

Inconsistency with earlier EPA studies: Some commenters claimed that earlier EPA studies and utility emission rulemakings supported the existence of the NO_X/load relationship.

Examples to show presence of a NO_X/load relationship: Many of the commenters on this issue included site-specific data intended to document the presence of a well-correlated NO_X/load relationship.

On the other hand, some commenters who supported EPA's use of the low NO_X period for evaluating the performance of LNBs also said EPA's comparison of load-weighted annual average NO_X emission rates vs. average NO_X emission rates without the assumption of a NO_X/load relationship satisfactorily addresses this issue (see, for example, docket items IV–D–46, p. 5 and IV–D–56, p. 1). According to a state agency, the ''52-day time frame is representative of a wide range of operations in a facility'' because the load variations over a seven-day week are likely to be more significant than seasonal variations. This agency said that, for most load-following units, load changes are likely to be more significant between weekends and weekdays than between seasons. Only the highest base-loaded units do not exhibit this load cycle and such units are ''likely not affected by seasonal changes'' (see docket item IV–D–27, p. 9).

Response: After further extensive boiler-by-boiler analysis of NO_X and boiler load, using both data provided by commenters and reported independently under 40 CFR part 75 requirements, EPA has determined that the installation of LNBs dampens any NO_X/load correlation that may have existed at uncontrolled boilers and, in many instances, virtually eliminates any long-term relationship. A NO_X vs. load relationship appears to have persisted for none of the tangentially fired boilers and for only a few of the wall-fired boilers (Colbert 5, E.D. Edwards 2, Quindaro 2, and Jack Watson 5) in the LNB Application Database (see docket item IV–A–6, pp. 4–2 through 4–7). However, despite these findings, in response to commenters' insistence that a definite functional relationship exists between NO_X and boiler load, EPA has employed a NO_X/load weighting scheme in establishing NO_X emission limits in this final rule. This load-weighting method incorporates at least two distinct improvements over the method used for the proposed rule analysis. First, following commenters' recommendation, the load weighting method employs ten load bins consistent with the convention specified in 40 CFR part 75, rather than the 25–MW increments used in the proposal. Second, the method uses post-retrofit CEM data over the longer post-optimization period, rather than the 52-day low NO_X period, to estimate mean hourly NO_X emission rates for each load bin, thus making it unnecessary to combine load bins due to sparse data. (Commenters had also said the combining of load bins with little or no data tended to mask the NO_X/load relationship. See docket item, IV–D–65, p. 35.) The load weighting method uses hourly boiler or common stack load as reported in the CEM data set for 1995 to establish the frequency of operation in different load bins over a year. EPA has rigorously investigated the relationship of individual load patterns of boilers sharing a common stack to the combined load patterns over a year and, thus, to the annual average NO_X emissions for the common stack (see discussion of common stack issues in section III.A.3.v of this preamble). Finally, EPA has compared, where data are available, boiler or common stack load patterns for 1994 and 1995 to assess inter-year variations in dispatch and demand for electrical power generation (see docket item IV–A–6).

This improved load weighting scheme accounts for any potential impact that annual load dispatch patterns may have on NO_X emissions. Its use should allay concerns raised by commenters on how the presence of a NO_X/load relationship might impede accurate assessment of long-term LNB performance. In addition, EPA's specific responses to the main NO_X/load issues are presented below:

Lack of statistical measures to quantify the extent of the NO_X/load relationship: Even among those commenters who most strongly assert the presence of a NO_X/load correlation, there is little consistency from boiler to boiler in either the functional form or the direction of the NO_X/load relationship. For example, of the three commenters submitting regression equations as evidence of a NO_X/load relationship, one was based on a cubic model (see docket item IV–D–20, Figure 3), another was based on a logarithmic model (see docket item IV–G–14, p. 3), and a third was based on a quadratic model (see docket item IV–G–16). A fourth commenter, represented the NO_X/load relationship from one-third to full load for eight boilers as straight line plots with slopes varying from approximately 15° to 45° (see docket item IV–D–72, Attachment 1). Although no supporting documentation was provided explaining how these plots were derived, they would imply a linear model was appropriate. The situation is further complicated when a NO_X/load relationship is discernible over only a portion of the load range. This is particularly an issue for wall-fired boilers retrofit with LNBs. EPA's plots of data from post-retrofit wall-fired boilers show that if a NO_X/load relationship is discernible at all, it occurs almost entirely in the upper 10–20% of the boiler load range.

The absence of a consistent functional form for the NO_X/load relationship and a failure to persist across the full load range makes application of a statistical measure to quantify the extent of the NO_X/load correlation difficult. Nonetheless, assuming a linear relationship between NO_X and boiler load, EPA estimated the strength of correlation as indexed by R^2 during post-retrofit period for 30 wall-fired and 11 tangentially fired boilers or common stacks in the LNB Application Database and, during the pre-retrofit period, for 13 wall-fired and 6 tangentially fired boilers or common stacks (see docket item IV–A–6, Cadmus Group 1 technical report, Table 4–1). The R^2 statistic measures the fraction of the variability in the dependent variable, hourly average NO_X emission rate, explained by the model. EPA chose an R^2 of 40% as a threshold for detection of the possible existence of a predictable correlation. For the post-retrofit hourly average NO_X emission rate measurements, only 13% of the wall-fired and none of the tangentially fired boilers or common stacks had an R^2 of 40% or higher (suggesting no predictable correlation). EPA compared the load dispatch pattern during the post-optimization period for each boiler or common stack crossing the R^2 threshold to its annual dispatch pattern in 1995 and concluded the patterns were similar enough that the improved load-weighting methodology would mitigate the effects of any NO_X/load correlation on estimated controlled annual average emission rates.

Inconsistency with earlier EPA studies: Earlier technical analyses performed for EPA in conjunction with other utility NO_X emission rulemakings generally adopted the industry accepted presumption of a NO_X vs. boiler load relationship. However, this was almost exclusively for uncontrolled Group 1 boilers, not boilers retrofit with LNBs. Prior studies also showed the direction, magnitude, and form of this correlation to be both highly boiler-specific and difficult to predict. (See, for example, docket item IV–J–20). Thus, for example, in these earlier studies, some uncontrolled tangentially fired boilers exhibit increasing NO_X emission rates with decreasing boiler loads, others show precisely the reverse correlation, and still others have U-shaped curves. Uncontrolled wall-fired boilers typically exhibit increasing NO_X emission rates with increasing boiler loads. However, this relationship was not found to be universally valid either, and the strength of the correlation, when present, varies considerably from one boiler to another.

For this final rule, EPA's analysis is more exhaustive than these earlier studies. It encompassed more boilers, longer data streams, and better quality data. Separate graphs were generated for every boiler or common stack in the LNB Application Database, plotting NO_X hourly emission rates as a function of hourly load, using long-term quality assured CEM data. To allow comparison of uncontrolled and controlled emissions, wherever available, pre- and post-retrofit hourly data were plotted on the same graph, differentiated by distinct symbols.

A comparison of the pre-retrofit and post-retrofit plots shows that, with one exception, for both wall-fired boilers and tangentially fired boilers, if any NO_X vs. load relationship existed for uncontrolled emissions, the installation of LNBs both reduced the magnitude and shortened the effective range of that relationship.

As discussed above, EPA also developed a statistical measure (R^2) of the strength of the correlation between NO_X and boiler load, assuming a linear relationship. This statistical analysis corroborates the visual assessment of the data plots. For the post-retrofit hourly average NO_X emission rate measurements, only 13% of the wall-fired and none of the tangentially fired boilers or common stacks had an R^2 of 40% or higher, suggesting possible presence of a predictable correlation. Even though this analysis confirms that the occurrence of a NO_X-load relationship is generally slight and for only some boilers, to eliminate all concerns in this regard, EPA has based the final rule on load-weighted annual average NO_X emission rates (instead of a straight average emission rates) observed over the post-optimization period (instead of the 52-day low NO_X period).

Examples to show presence of a NO_X/load relationship: A number of commenters provided data intended to demonstrate the presence of a NO_X/load relationship. The submissions either had drawbacks which rendered their conclusions questionable or corroborate EPA's finding that the installation and operation of LNBs generally dampen any pre-retrofit correlation of NO_X and boiler load and, in many instances, virtually eliminate any long-term relationship. The salient aspects of each submission and EPA's responses are summarized below:

Docket item IV–D–020, Figure 20: Using CEM data for the period 06/30/95 through 07/18/95, this submission included a regression analysis for a 550 MW wall-fired boiler retrofit with LNBs. The regression model fit NO_X emissions to boiler load during the period analyzed. The R^2 statistic, which captures the explanatory power of the regression model, was 77.3%, indicative of a good fit with the data.

There were a number of drawbacks, however, with the analysis. First, the period analyzed represents only 19 calendar days. This is too short a period to adequately represent long-term performance or to distinguish a strong, but transitory, NO_X/load correlation from a persistent NO_X/load correlation.

Second, the data plot shows a wide range of NO_X emission rate points at zero load. These appear to be spurious measurements which improperly dominated the regression results.

Docket item IV–G–14, Tables 1–4 and Figures 1 and 2: This submission included ''before LNB'' and ''after LNB'' regression analyses for a 80 MW tangentially fired boiler. The ''before LNB'' regression is based on five-and-a-half months of CEM data and the ''after LNB'' regression is based on eight months of CEM data. During the ''after LNB'' period, this boiler had to comply with a state-mandated NO_X RACT limit of 0.42 lb/mmBtu on a 24-hr average basis. The commenter rightly excludes NO_X emission data points for periods when load is zero, which is consistent with EPA's DQO 3D.[8] In both the ''before LNB'' and ''after LNB'' case, the highest NO_X emission rate is at minimum load. The R_2 statistic in the ''before LNB'' regression was 57.8%, indicating that the model had moderate explanatory power, whereas the R_2 value in the ''after LNB'' regression was only 29.1%, indicating poor explanatory power.[9] EPA believes that this ''before LNB'' and ''after LNB'' comparative regression analysis illustrates how the installation and operation of LNBs can dampen any NO_X vs. load relationship which may be observed at uncontrolled boilers.

Docket items IV–D–65, Enclosure 8; IV–D–23, Attachment 1; IV–D–73, Attachment A: Several commenters submitted line plots or histograms of average and/or maximum NO_X emission rates recorded for different load intervals or ''bins''. There were several problems with these submissions. First, although they criticize EPA in this regard, the commenters themselves do not develop any statistical measures of the association between NO_X and load for the data they submit (perhaps because it, too, fails to demonstrate the presumed relationship). Nor do they suggest functional representations for their plots.

A second drawback of these submissions is that some of the plots represent boilers retrofit with LNBs plus separated overfire air. As noted previously, such applications cannot be considered in this rulemaking.

Third, while the submitted graphs appear to support the commenters' statements about the existence of a NO_X vs. load relationship for the boilers analyzed, the use of a single value (whether the average or maximum) to represent all values in a load range bin is misleading. It hides the variability within the bin, thereby avoiding the issue of whether the range of values in one bin are distinguishable from those in another bin.

To address this issue EPA generated NO_X/load box-and-whisker plots for each boiler or common stack in the LNB Application Database. The box-and-whisker representation not only shows a mid-point value (the median), but it also characterizes the range of values found in each bin by displaying the minimum, maximum, and first and third quartile values. Where sufficient data were available, separate graphs were created for NO_X/load correlation before and after LNB retrofits. In response to the commenter's criticism that EPA's earlier analysis for the proposed rule had used too few load bins, ten load bins (in 10 percent increments from zero to maximum gross unit load) were used in all the NO_X/load analyses for the final rule.

The box-and-whisker plots reveal so much overlap in NO_X values from bin to bin that drawing conclusions about a NO_X/load relationship is technically inappropriate. This is particularly true for the post-retrofit situation.

Docket items IV–D–73, p. 5 and Attachment A; IV–D–65, p. 32: One utility reported that the NO_X emission rate guarantee, in its contract for LNBs on a 375 MW wall-fired boiler (E.D. Edwards 3), ''[is] designed specifically to achieve specific NO_X rates at specific loads.'' The annual NO_X emission rate is guaranteed to meet 0.50 lb/mmBtu based on a specified capacity. The NO_X emission rate guarantees for particular loads range from 0.28 lb/mmBtu at 40% of MCR (150 MW) to 0.63 lb/mmBtu at 100% of MCR (375 MW). The commenter also submitted graphs depicting the ''remarkable NO_X vs. load relationship'' for another wall-fired boiler (E.D. Edwards 2). The graphs plotted the average, maximum, and minimum hourly NO_X emission rates recorded in each of ten load bins for the four quarters of 1995 as well as the entire year.

EPA has analyzed all the post-retrofit CEM data for E.D. Edwards 2 to evaluate the extent of a discernible NO_X/load relationship. The analysis confirmed the existence of a well-defined NO_X vs. load relationship for this boiler, but only in the upper 20% of the load range (see docket item IV–A–6, Appendix D).

Another commenter noted that Babcock & Wilcox (B&W), a primary designer of wall-fired boilers and a major LNB vendor in the U.S., attests to the existence of a NO_X/load correlation. This commenter said EPA did not find a strong NO_X vs. load relationship because EPA did not examine closely the post-retrofit CEM data for wall-fired boilers designed by B&W. B&W has stated, ''a definite correlation [exists] between NO_X emissions and boiler load'' (see docket item IV–D–65, p. 32).

The LNB Application Database contains 18 wall-fired boilers designed by B&W. Five of these boilers, EPA believes, have also been retrofit with LNBs manufactured by B&W (Model DRB–XCL). Only one B&W boiler and none of the B&W LNB retrofits appeared among the wall-fired boilers or common

[8] The commenter applies a cutoff at 5 MW, to exclude periods when a small positive heat input may be recorded, but boiler load is actually zero.

[9] The commenter concludes that the relationship between NO_X and boiler load is much less well-defined after LNB retrofit, but maintains the relationship still exists based on an analysis of variance which produces a correlation coefficient of −0.54.

stacks that had an R^2 of 40% or higher for the correlation of post-retrofit hourly average NO_X emission rate measurements with boiler load.

3. Analysis Method Used to Establish Reasonably Achievable Emission Limitations for Phase II, Group 1 Boilers

i. Background

For the proposed rule, EPA used a three-step analytical procedure for establishing reasonably achievable annual emission limitations for the populations of wall-fired boilers and tangentially-fired boilers, retrofit with LNBs, that would be subject to any revised emission limitations (i.e., those units subject to NO_X emission limitations only in Phase II). The first step (Model Building) consisted of deriving linear regression equations, one for wall-fired boilers and another for tangentially fired boilers, that captured the percent reduction in post-retrofit load-weighted annual average NO_X emission rate as a function of the uncontrolled emission rate for boilers in the LNB Application Database. The second step (Calculation of Achievable Emission Rates) was to enter the uncontrolled emission rates of the Phase II boilers into the regression equations in order to derive the controlled NO_X emission rate that each boiler could be expected to achieve by LNB retrofit. Using the resulting set of achievable emission rates, the third step was to identify the annual emission limitation that a specified percentage (i.e., 85 to 90%) of the Phase II boilers could achieve. Separate limits were identified for wall-fired boilers and for tangentially fired boilers.

This three-step procedure afforded several advantages. First, by using regression equations, the estimates of achievable emission rates were not rough extrapolations from average Phase I post-retrofit experience but were estimates specifically tailored to the pre-retrofit NO_X emission rates actually observed at the Phase II units. As shown in Table 12 in the preamble to the proposed rule (61 FR 1452), Phase II units typically operate at lower uncontrolled emission rates than Phase I units (i.e., 23% lower for wall-fired boilers and 18% lower for tangentially fired boilers) so a simple extrapolation of the experience of the mostly Phase I units in the LNB Application Database would significantly underestimate the number of boilers that would be expected to achieve a given emission limitation.

Second, using regression models also allowed for quantitative, statistical evaluation of the explanatory power implicit in the resulting estimates and enabled objective comparison of different analytical approaches. Incorporating load-weighted annual averaging into Step 1 of the procedure meant that any NO_X/load effects would be factored into the model.

Furthermore, responding to comments criticizing the proposed rule for basing the regression model on 52 days of low NO_X post-retrofit emission data, the final rule uses the much longer post-optimization data stream to build the regression equations. Use of this longer data stream increases confidence that the regression equations model the long-term behavior of boilers in the LNB Application Database.

The Agency received detailed comments from utilities and a utility association on three data issues and related technical components of EPA's analysis methods. First, commenters questioned EPA's use of short-term data to characterize pre-retrofit uncontrolled emission levels when, for some boilers, long-term data were available. Uncontrolled emission rates are used in Step 1 (Model Building) and Step 2 (Calculation of Achievable Emission Rates) of EPA's analytical procedure for deriving the annual emission limitations. Second, in a related data issue, commenters believed that the uncontrolled emission rates used for the affected population of Phase II boilers were biased low, due partly to a misperception about how controlled NSPS units were treated in Step 2. (Controlled NSPS units have older LNBs or some other early type of NO_X combustion control installed as original equipment, so their measured baseline emission rates do not represent uncontrolled emissions.) Third, commenters disagreed with or raised questions about certain technical assumptions built into the models—namely, the methods used to estimate percent NO_X reduction outside the range of the observed model inputs and the form of the regression model. Finally, commenters said that monitored emissions data from boilers sharing a common stack should be used cautiously, if at all, when evaluating LNB performance and offered suggestions on how to properly assess such measurements.

Salient background points regarding EPA's treatment of certain data issues for the proposed rule are summarized in the paragraphs below. The subsequent sections of this preamble discuss the comments more fully, EPA's response to the issues raised, and how these data and technical components are treated in the analysis supporting the final rule.

EPA is fully cognizant that ''long-term data collection is the definitive method to determine actual NO_X reduction characteristics of a low NO_X combustion system'' and that DOE Clean Coal Technology Demonstrations routinely collect long-term CEM data to measure the baseline uncontrolled emission rate (see docket item II–I–99, p. 8). At the time of the proposed rule analysis, however, EPA had quality assured pre-retrofit long-term CEM data for only 21% of the boilers in the LNB Application Database. Such CEM data were unavailable for most of the wall-fired boilers (21 of 24) and over half of the tangentially fired boilers (5 of 9). Generally, CEM data on uncontrolled emissions were unavailable because the LNB retrofit had begun prior to certification of the CEM system in accordance with 40 CFR part 75. EPA decided that it was preferable to use consistent, quality assured, short-term measurements of uncontrolled emission rates based on EPA Reference Method, certified CEM, or other test data rather than to limit the LNB Application Database to only those boilers for which EPA had quality assured, pre-retrofit, long-term CEM data. EPA also rejected the possible option of using short-term data for some boilers and long-term data for other boilers for the reasons explained in detail in the next section of this preamble.

To assure that consistent data of known high-quality was used for the model projections, EPA identified specific sources of acceptable short-term uncontrolled emission rate data. These sources, listed in priority order, are: (1) Short-term CEM data reported in monitor certification review (CREV) tests (see docket item II–A–9); (2) utility-reported CEM or EPA Reference Method test data provided on the Acid Rain Cost Form for NO_X Control Costs; and (3) other short-term CEM or test data provided by utilities, generally as a correction or update to data previously submitted to EPA.

For the proposed rule analysis, EPA obtained acceptable short-term uncontrolled emission rate data for all units in the LNB Application Database and for 69% of the Phase II boiler population. For the proposal, EPA used uncontrolled emission rates based on long-term CEM data or, as a last resort, estimates in the National Utility Reference File (NURF), which were developed using emission factors, for the other boilers in the Phase II population. For the final rule, EPA has located substantial additional quality assured short-term uncontrolled emission rate data and has discontinued using both long-term CEM and NURF estimates for the Step 2 (Calculation of Achievable Emission Rates) projections.

ii. Short-term vs. Long-Term Uncontrolled Emission Rate Data

Comment/Analysis. EPA received approximately 7 comment letters (from 6 utilities and 1 utility association) on the use of short-term uncontrolled emission rate data for assessing the performance of LNBs applied to Group 1 boilers. Concern was expressed that using short-term uncontrolled emission rates to build the regression equation would cause the model to overestimate or, at least wrongly estimate, the achievable reductions, because short-term uncontrolled emissions would tend to reflect full-load uncontrolled emissions whereas the corresponding controlled emissions values, used to build the regression model, would represent the ''average of 1248 points at different loads'' (see docket item IV–D–65, p. 51). The comments raised two issues:

(1) *Misuse of Short-Term Data:* EPA used short-term uncontrolled emission rate data even when, for some boilers, quality assured long-term CEM data were available for determining pre-retrofit uncontrolled emission rates. (See docket items IV–D–38, p. 3 and IV–D–65, pp. 50–51. No commenter suggested, however, that EPA restrict the analysis to only those boilers for which pre-retrofit, long-term CEM data were available. EPA notes that one commenter, who recommended using a full year of pre-retrofit monitoring data, selected CREV emission rates as the best available substitute for baseline measurements when long-term CEM data were not available.[10]

(2) *Load Cell 10 Approach:* Several commenters said the use of short-term measurements of pre-retrofit uncontrolled emission rates in both the EPA and DOE studies led to high estimates of uncontrolled emission rates which, in turn, exaggerated LNB reduction efficiencies (see, for example, docket items IV–D–11, p. 3 and IV–D–72, p. 3). (Traditionally, LNB percent reduction efficiency has been measured on a consistent pre-retrofit/post-retrofit basis, normally short-term to short-term though occasionally long-term to long-term.) The load cell 10 approach was suggested by one commenter as a solution: its argument runs as follows. In building the regression model, since EPA used short-term uncontrolled emission rate data, which tends to be obtained at full load, for consistency the post-retrofit controlled emission values should have been ''the average NO_X data in load cell 10 or the highest load cell experienced at the boiler,'' not the average of controlled emission values at all load levels. (See docket item IV–D–65, p. 52.)

Response. (1) Misuse of Short-Term Data: For analytical, practical, and statistical reasons, EPA chose to use short-term uncontrolled emission data rather than only long-term uncontrolled emission data or a combination of short-term and long-term uncontrolled emission data. For analytical consistency, it is desirable, if not essential, for all uncontrolled emission data to be long-term or short-term but not a mixture of both. Maintaining this consistency across both the LNB Application Database and the Phase II, Group 1 boiler population database provides the logical underpinnings for drawing inferences from the regression model to the Phase II data set, insofar as the uncontrolled emission rate represents the independent variable in the regression model. From an analytical standpoint it is perfectly acceptable for the regression model's dependent variable (controlled emission rate) to be based on a different duration standard (e.g., long-term as opposed to short-term) than the independent variable.

Practical and statistical considerations favored the selection of short-term data over long-term data. In particular, it was not possible to obtain quality assured long-term uncontrolled data for many units because CEM requirements for Phase I boilers were generally coincident with LNB retrofits. Fewer data points would have reduced the statistical confidence in the conclusions drawn from the data.

Some commenters were apparently unaware of certain practical data limitations. One commenter said, ''utilities have been required to provide EPA with CEM data since at least January 1, 1995 (pursuant to 40 CFR part 75 . . . (so) the CEM NO_X data should be used in most instances for uncontrolled emissions'' (see docket item IV–D–65, p. 51). However, while desirable, this approach was not a practical option. Since utilities are not required to report even approximate dates of LNB installations for Phase II units to EPA, as they did in Phase I on the Acid Rain Cost Form for NO_X Control Costs, it is exceedingly difficult to accurately determine the control status of each unit, the date and hour on which a specific unit is being taken off-line for installation of LNBs, and the end (i.e., date and hour) of the pre-retrofit monitoring period. In contrast, reliable information on unit control status accompanies the short-term uncontrolled emission data in the CREV database since utilities are required to report the type of NO_X controls, if any, on each unit to EPA with the annual certification review test data.

Using the short-term CREV data for the final rulemaking, EPA was able to amass uncontrolled NO_X emission rates for 85% of the Phase II, Group 1 boilers. This includes virtually every Phase II, Group 1 boiler whose uncontrolled emissions were not otherwise obscured by complex ''mixed'' common stack arrangements, either with respect to boiler type (e.g., wall and tangentially fired boilers sharing a common stack) or control status (e.g., controlled and uncontrolled boilers sharing a common stack). Quality assured short-term uncontrolled emission data were obtained for an additional 13% of the Phase II, Group 1 boilers from other acceptable sources. In all, about 98% of the affected Phase II, Group 1 boilers were included in the Step 2 analysis (Calculation of Achievable Emission Rates) for the final rule.

Notwithstanding commenters' concerns, the ability of the regression model to estimate achievable NO_X emission limits is not diminished by using short-term uncontrolled emission values as the regression model's independent variable. This is a consequence of the structure of the model. In the model building stage (Step 1) of EPA's analytical procedure a functional relationship is established between short-term uncontrolled emissions and the post-optimization load-weighted controlled average emission rate achieved by boilers in the LNB Application Database. In Step 2, as long as the Phase II short-term uncontrolled emission values that are fed into the regression equation remain within the range for which the model was designed, the model's ability to estimate the corresponding achievable post-optimization annual emission rate should remain unimpaired.

To evaluate the effect of using short-term rather than long-term data for uncontrolled emission rate on the annual emission limitations derived from the 3-step analytical procedure, EPA was able to assemble a database of 18 boilers containing long-term pre-

[10] This commenter combined annual CEM and CREV baseline measures when assessing the effect of a fuel switch on NO_X emissions for four boilers the utility owns and operates. The analysis used annual CEM data for the ''before'' measurement on two boilers, CREV emission rates for the ''before'' measurement on two other boilers, and annual CEM data for the ''after'' measurement on all four boilers (see docket item IV–D–038, Attachment A).

retrofit emission rate values.[11] This database was used to perform sensitivity tests on the effect of using long-term vs. short-term measurements of uncontrolled emission rate on the projections of the number of Phase II, Group 1 boilers that could comply with various performance standards. For these tests, EPA used the long-term, instead of short-term, measurements for uncontrolled emission rate in Step 1 (Model Building) wherever such pre-retrofit data were available (18 out of 53 boilers). The R^2 values for the resulting regression models based on load-weighted annual average emission rates over the post-optimization period were 65.3% (wall-fired boilers) and 78.9% (tangentially fired boilers), indicating acceptable fit (see docket item IV–A–6, Tables 4–6a and 4–6b). Applying these models to the Phase II, Group 1 data set of uncontrolled emission rates produced the results shown in docket item IV–A–6, Tables 4–7a and 4–7b. Within the primary range of interest (i.e., from 80th to 90th percentiles), the percentage of boilers estimated to achieve a specified emission limit using the long-term data typically varies by less than 2% (and not more than 5%) from the percentage derived using strictly short-term data. Both positive and negative differences occur, depending on the exact percentile and type of boiler, suggesting the emission limit could be lowered in some instances and raised in others. EPA concludes that using short-term measurements of uncontrolled emission rate has not systematically nor significantly lowered the resulting estimates of controlled emission rates achievable by Phase II, Group 1 boilers retrofit with LNBs.

(2) *Load Cell 10:* Use of load weighting in EPA's regression model makes the load cell 10 restriction unnecessary. As noted in the preceding paragraph, the regression model establishes a functional relationship between the short-term uncontrolled emission rate and the load-weighted annual average emission rate maintained over the post-optimization period. If, as the commenter maintains, the load level can be assumed to relatively constant for all the short-term uncontrolled emission data (i.e., at full load), all the more reason exists for the functional relationship captured in EPA's regression equation to remain intact.

The load cell 10 approach would establish a functional relationship between the short-term uncontrolled emission rate and the long-term controlled emission rate achieved when the unit is operating at essentially full load (i.e., in ''load cell 10,'' at 90–100% of total unit operating load).[12] The dependent variable in this regression model would be the unit's average ''load cell 10'' (or full-load) controlled emission rate. This approach would discard all post-retrofit CEM hourly data recorded when the unit is operating in load cells 1 through 9 and thus, would not be representative of unit's average emission rate over a calendar year. This would be inconsistent with the purpose under section 407(b)(2) of analyzing LNB performance, which is to determine whether the existing Group 1 emission limitation applied on any annual average basis should be made more stringent.

EPA notes that for boilers where NO_X emission rate increases with increasing load, the achievable full-load emission rate determined using the load cell 10 approach would be higher than the average emission rate observed over varying boiler loads throughout a year. At least 25% of the wall-fired boilers in the LNB Application Database operated at full load for less than 20% of total operating hours in 1995. Basing the annual performance standard on an achievable full-load emission rate would inappropriately bias the emission limitation since many boilers are typically operating at lower loads most of the time.

iii. Potential for Low Bias in Phase II Uncontrolled Emission Rate Estimates/Treatment of NSPS Units

Comments/Analysis: EPA received approximately 5 comment letters (from 3 utilities and 2 utility associations) saying that EPA's estimates of uncontrolled emission rates for the Phase II boiler population appeared too low. The commenters cited different reasons for this outcome and some submitted unit-specific estimates of uncontrolled emission rate (see, for example, docket item IV–D–39, p. 3). Several commenters attributed the seemingly low rates to the inclusion of NSPS units in the Phase II boiler population baseline of uncontrolled emission rates. As one commenter stated, ''the NSPS units are by original design low NO_X emitters . . . and (if included), the overall Phase II, Group 1 boiler baseline rate will be artificially biased downward and will lead to conclusions that overstate the ability of both non-NSPS and NSPS units to achieve the final emission limit for this boiler group'' (See docket item IV–D–72, p. 3).

Response: These commenters correctly noted that the technical support document for the proposed rule does not contain a separate baseline for NSPS units nor any explicit discussion of the how these units are treated in Step 1 (Model Building) and Step 2 (Calculation of Achievable Emission Rates) of EPA's projection analyses. EPA developed a table comparing the average uncontrolled emission rates, by boiler category, for the Phase II, Group 1 boiler population with and without NSPS Subpart D and Subpart Da units against the Phase I, Group 1 boiler population (see docket item IV–A–10). This table shows that average uncontrolled emission rate for the Phase II population excluding units identified as ''NSPS-vintage units'' [13] is definitely lower than the average uncontrolled emission rate for the Phase I population: the difference is estimated as 10% for wall-fired boilers and 9% for tangentially fired boilers.

Subsequent to the rule proposal, EPA obtained additional data to refine both the classification of Phase II units subject to NSPS NO_X requirements, including both Subpart D and Subpart Da, and the description of any pre-existing NO_X combustion controls installed on these units. EPA notes that since no percent reduction standard for NO_X applies to Subpart D boilers, Subpart D units frequently do not have combustion controls installed as original equipment. Subpart Da boilers are required to achieve a specified percent reduction for NO_X, so Subpart Da units generally had some early form of NO_X combustion controls installed prior to November 15, 1990.

As discussed previously in section III.A.1 of this preamble, EPA has excluded controlled NSPS boilers from the model building regression analyses because their measured baseline emission rates do not represent uncontrolled emissions. However, EPA has included all NSPS boilers, controlled and uncontrolled, in the

[11] Long-term pre-retrofit emission rate values were defined from the hourly CEM data as follows. The pre-retrofit period, which is called ''pre-retrofit minus 30 days'' (abbreviated as ''30-day pre-rate'' in tabular column headings), starts at the beginning of the CEM data set. Because some uncertainty exists as to the exact date of the LNB retrofit, EPA used only quality assured CEM data recorded more than 30 calendar days before the primary boiler outage for installation of LNBs. These days are excluded to assure that no post-retrofit data are mixed with pre-retrofit data in the baseline measurement. Consistent with the post-retrofit situation, EPA included only boilers which had at least 1,248 hours (or 52 days) of quality assured pre-retrofit CEM data.

[12] The ''load cell 10 approach'' uses only data recorded for the highest load cell experienced at the boiler, which is normally load cell 10.

[13] This classification of ''NSPS-vintage units'' was based on boiler age as reported in the NURF data file.

Phase II boiler data set on which the regression models are applied because coal-fired NSPS boilers are subject to this rulemaking.

NSPS boilers are by original design inherently lower NO_X emitters and have larger furnace volumes per MW than most pre-NSPS boilers which makes it easier for NSPS boilers, when retrofit with current LNB technology, to achieve specified levels of controlled NO_X emission rates.[14] The only NSPS boiler for which EPA has long-term post-retrofit CEM data (North Valmy 1) corroborates the assessment that NSPS boilers, when retrofit with current LNB technology, can generally achieve lower NO_X levels than most pre-NSPS boilers. North Valmy 1 sustained an average controlled emission rate of 0.264 for calendar year 1995 (see docket item IV–A–9). Although several commenters discussed this particular LNB installation, none provided any information which would suggest this boiler is not typical of controlled NSPS boilers.

iv. Technical Assumptions Used in Group 1 Regression Model

EPA received approximately 3 comment letters (from 2 utilities and one utility association) on certain technical assumptions in the Group 1 regression model approach—namely, the methods used to estimate percent NO_X reduction outside the range of the observed model inputs and the form of the regression model.

a. Estimation Method for Units with High Uncontrolled Emission Rates

Comment/Analysis: Commenters said that percent NO_X reductions and controlled emission rates that seemed to be predicted by EPA's regression model at theoretically high values of uncontrolled emission rates were ''curious'' and seemingly contrary to experience and common sense.

Any regression model is statistically verifiable only for the range of data used to construct the model. Not realizing that EPA had assumed the percent NO_X reduction for any Phase II boilers with uncontrolled emission rates above the highest value in the LNB Application Database was equal to the percent NO_X reduction estimated for the highest data point (see docket item II–F–2, p. 4–3), some commenters said the model ''predicts NO_X control scenarios that lead to absurd results'' such that if one can only increase uncontrolled NO_X emissions to a sufficiently high level, one could achieve 100% NO_X removal!'' (see docket item IV–D–65, p. 43 and IV–G–16, p. 6).

Response: EPA's failure in the proposal to explicitly state a caveat that is routinely assumed in regression analysis led these commenters to draw erroneous conclusions from the model. The required caveat is that the statistically verifiable fit of a regression model is only assured within the range of the data actually used to construct the model. Thus, for the regression equations used in the proposed rule, the statistically verifiable range (in uncontrolled emission rates) for wall-fired boilers was from 0.51 lb/mmBtu to 1.34 lb/mmBtu and for tangentially fired boilers was from 0.48 lb/mmBtu to 0.66 lb/mmBtu. With the addition of 20 boilers to the LNB Application Database in support of the final rulemaking, the current upper limits on the ranges have increased to 1.41 lb/mmBtu for wall-fired, and to 0.86 lb/mmBtu for tangentially fired boilers (see docket item IV–A–6, Tables 3–1a and 3–1b).

Had the commenters been cognizant of the caveat described in the previous paragraph, they probably would not have drawn the admittedly ''curious'' conclusions noted above. Further, had they assumed proper application of the model instead of presuming improper application, they would have noted that the model was not applied outside its effective range.

Similarly, the commenters were also troubled by the seeming implication that the mathematical form of the regression seemed to pre-ordain that emissions could never exceed a certain maximum bound. As the commenter in docket item IV–D–65 puts it: The model predicts ''. . . that controlled emissions at wall-fired boilers will never exceed 0.454 lb/mmBtu.'' In fact, based on existing data, the model simply shows a maximum predicted emission reduction over the model's statistically verifiable range. For points outside the range of the model, no specific bound is implied, and the maximum observed emission reduction was not exceeded.

As in the proposal, when estimating the controlled emission rates for Phase II, Group 1 boilers with uncontrolled emission rates higher than the verifiable range of the model, EPA made the following assumption[15]: the percent NO_X emission reduction for such boilers was assumed to be no greater than the reduction obtained by the boiler with the highest uncontrolled emission rate in the LNB Application Database. In effect, this assumption would lead to emission limits that are less stringent than if it were assumed that the emission reductions for such boilers could exceed those of boilers in the LNB Application Database.

b. Form of the Regression Model

In both the analysis for the proposed and final rules, EPA considered two alternative forms of the regression models used to predict the achievable controlled emission rates from uncontrolled boiler NO_X emission rates:

Model #1 (One-step approach): Direct linear fit, regressing controlled emission rate on uncontrolled emission rate.

Model #2 (Two-step approach): Step 1—Direct linear fit, regressing percent NO_X reduction on uncontrolled emission rate. Step 2—Controlled emission rate is computed from the percent reduction derived in Step 1.

EPA chose Model #2 because the regression equations derived using this model explain the data better than those derived using Model #1. Statistically, this is expressed in the higher ''R^2 value'' of Model #2 (R^2=73.1% for wall-fired boilers; R^2=70.7% for tangentially-fired boilers) as compared to Model #1 (R^2=59.7% for wall-fired boilers; R^2=17.0% for tangentially-fired boilers) (see docket item IV–A–6, Tables 4–9a and 4–9b).

Comment/Analysis: A commenter criticized EPA's choice of Model #2, saying that it models the wrong parameter: ''. . . while the key issue in this rulemaking is the level of controlled emissions at Phase II, Group 1 boilers, . . . (EPA's) model is designed to predict NO_X removal efficiency—a related but secondary parameter'' (docket item IV–D–65, p. 45). Consequently, the commenter questioned the meaningfulness of a superior R^2 value from a model that regresses percent reduction on uncontrolled emissions, when the true parameter of interest is not percent emission reduction but controlled emissions: ''. . . just because Model 2 predicts removal efficiency better than Model 1 predicts controlled emissions does *not* mean that Model 2 predicts controlled emissions better than Model 1'' (docket item IV–D–65, pp. 45–46).

Response: While on the surface this criticism appears plausible, on further investigation it is incorrect because the two-step approach of Model #2 is algebraically equivalent to a one-step second order linear regression model that directly regresses controlled

[14] Reference: Smith, L. 1988. Evaluation of Radian/EPA NO_X Reduction Estimation Procedures. ETEC–88–20046. February.

[15] Only 1 wall-fired boiler and 3 tangentially fired boilers in the Phase II boiler data set (representing less than 1% and less than 2%, respectively, of the affected populations) have measured uncontrolled emission rates higher than the range used to construct the regression model and thus fall in this category.

emissions on uncontrolled emissions.[16] Thus, although its two-step formulation makes Model #2 appear not to regress controlled emissions on uncontrolled emissions, in actuality, by simply restating Model #2 in its second-order form, it can be shown to be no different in this regard than Model #1: Both models regress controlled emissions on uncontrolled emissions: Model #1 using a first-order linear expression; and Model 2 using a second-order linear expression.

Interestingly, EPA's calculations indicate that had the Agency adopted Model #1, as advocated by the commenter (a large association of utilities), the resulting achievable annual emission rates at the 90th, 85th, and 80th percentiles, for both wall-fired boilers and tangentially fired boilers, would be approximately one-half to one percentage point lower (i.e., more stringent) than the achievable annual emission rates obtained using Model #2. (See docket item IV–A–6, Tables 4–10a and 4–10b). Thus, although EPA adopted Model #2 on strictly statistical grounds, it turns out that in the analysis for the final rule, Model #2 was more favorable than Model #1 to those commenters seeking less stringent emission limitations.

v. Common Stack Issues in Group 1 Analysis

Background: In the proposed rule analysis, EPA found no strong correlation between boiler operating loads and post-retrofit hourly average controlled emission rates for single-stack boilers in the LNB Application Database and therefore, assumed that two boilers of the same type (i.e., wall-fired or tangentially fired) and NO_X control status (i.e., both had LNBs only) sharing a common stack would have similar post-retrofit controlled emission rates. (EPA notes that some utilities also made this assumption when completing the Acid Rain Cost Form for NO_X Control Costs for their Phase I LNB retrofits and provided ''sister unit'' estimates of emission rates in instances where multiple units were sharing a common stack.) In EPA's analysis, therefore, the rates from similarly situated individual units at a common stack were assumed to be the same, and single boiler and multiple boiler data were analyzed together (i.e., the common stack emission rate was assigned to each constituent unit).

Comment/Analysis: EPA received approximately 4 comment letters (from 3 utilities and a utility association) on considerations for using common stack data when analyzing LNB performance applied to Group 1 boilers. One commenter advised EPA to ''use caution when evaluating NO_X data from combined stacks'' (see docket item IV–G–14, p. 1). Another commenter said EPA should ''either exclude common stack emissions data from its analysis, or revise its analysis based on data collected during periods when only a single unit [to a common stack] is operating'' (see docket item IV–D–65, p. 42).

EPA notes that the decision on how to treat common stack data has important ramifications for both: (1) The amount of post-retrofit CEM data available for analysis; and (2) the number and representativeness of LNB retrofit cases in the LNB Application Database. Sixteen (16) of the 39 wall-fired boilers (41%) and 6 of the 14 tangentially fired boilers (43%) in the LNB Application Database exhaust to common stacks with similarly situated boilers also in the database; collectively, these boilers contribute 242,000 hours to the total of 477,800 hours of post-retrofit CEM data available through the second quarter of 1996 to support the final rule. Twenty-two (22) of the boilers sharing a common stack have post-optimization periods spanning 11 calendar months or longer. EPA does not consider the approach of excluding common stack emissions data, suggested by one commenter, a viable option because disregarding the substantial collective experience of these boilers would clearly reduce statistical confidence in the resulting assessment of LNB performance.

Accordingly, EPA has sought other ways to address the commenters' criticism that EPA did not provide credible support in the proposed rule analysis for its treatment of common stack data. The specific concerns cited are: (1) Using the common stack post-retrofit NO_X emission rate as the emission rate for each individual boiler sharing the common stack in the regression analyses; and (2) developing NO_X/load curves for common stacks by summing the NO_X emissions and loads from the boilers sharing the stack (see docket item IV–D–65, pp. 37–38).

Response: EPA has performed extensive follow-up analysis on whether measured common stack emission rate data over the post-optimization period reflects the combined annual averages of individual boilers sharing the common stack. EPA compared the combined common stack emission rate to the individual-unit emission rates at every common stack in the LNB Application Database for which usable post-retrofit CEM data could be identified for periods when only a single unit was operating. In all, EPA studied 10 common stacks with 22 constituent boilers and over 19,800 hours of individual-unit emission rate data. The analysis included:

(1) Box and whisker plots: The plots present side-by-side displays of the range of emission rates at common stacks when all units were operating compared to when only single units were operating: for each common stack, separate plots were generated using emission rates observed during the low NO_X period and the post-optimization period. In both cases the plots show little difference between multiple-unit common stack emission rates and the individual unit emission rates over the averaging periods.

(2) Percent Difference Calculations: Computing the percent difference between the multiple-unit and single-unit average emission rates for the post-optimization averaging period revealed that, on average, the percent difference for the wall-fired boilers was −0.3%, while for the tangentially fired boilers the percent difference was 1.8%. (See docket item IV–A–6, Tables 4–8a and 4–8b.) This strongly indicates that, contrary to the belief of some commenters, there is not a significant disparity between the common stack and constituent unit NO_X emission rates for the post-optimization averaging period.

(3) Sensitivity Analysis: EPA performed a series of analyses to see how estimates of achievable annual emission limitations were affected by various treatments of common stack emissions. Three scenarios were investigated. In the first, the regression model was built using the constituent unit emission rates instead of the common stack emission rates. In the second, each common stack emission rate was used only once for each stack. In the third, the common stack emission rate was repeated for each unit. The third treatment is the same as that used by EPA in the proposed rule. The regression models fit the load-weighted data over the post-optimization averaging period approximately equally well, as measured by R^2, for the various treatments of common stack emissions data. (The R^2's ranged from 73.1–75.1% for the wall-fired boilers and from 62.8–72.1% for the tangentially fired boilers (see docket item IV–A–6, Tables 4–9a

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[16] The two-step version of Model #2 fits a first-order linear model $\hat{p}=\beta_0=\beta_1 U+\varepsilon$ data, where U is the regressor variable ''uncontrolled emissions'' and P is the response variable ''percent reduction.'' Then, in step 2, C, the controlled emission rate, is calculated from P using the equation $C=U(1–P/100)$. However, Model #2 (two step) can be reformulated as a one step second-order linear regression model, $\hat{C}=\beta'_0+\beta'_1 U+\beta_{11} U^2+\varepsilon'$. Like Model #1 (one-step), Model #2 (one step) regresses C on U.

and 4–9b.) The differences among the achievable annual average emission rates predicted by the regression models under the three scenarios at the 90th, 85th, and 80th percentiles varied by only 0.001–0.003 lb/mmBtu for wall-fired boilers and even less for tangentially fired boilers (see docket item IV–A–6, Tables 4–10a and 4–10b). The alternative scenarios produced estimates of achievable annual emission limitations no less stringent than the third treatment, which is used for today's final rule.

(4) Load Profile Analysis: One of the commenter's arguments against using common stack NO_X emission rates was the contention that the emission rate for the stack could be artificially low because the averaging period occurred during a time when only a single unit just happened to be operating at an untypically low emitting load profile. To respond to this concern, EPA verified that during the post-optimization averaging period the ''load profile'' (i.e., the distribution of load) of every unit exhausting to each common stack analyzed was congruent with the annual load profile for that unit. This analysis verified that no matter what configuration of boilers happened to be operating, the common stack emission rates used to build EPA's regression model could not have resulted from an atypical low emission load profile during the post-optimization averaging period.

With respect to the commenter's argument that EPA developed NO_X/load curves for common stacks by summing the NO_X emissions and loads from the boilers feeding the stack, the commenter appears to have misunderstood EPA's approach.

The commenter wrongly believed that EPA's analysis rests on one of three alternative assumptions: no NO_X/load relationship exists, identical NO_X/load relationships exist among constituent units, or identical loading patterns prevailed for all units during the averaging period (see docket item IV–D–65, p. 38). This misunderstanding led the commenter to offer a hypothetical illustration to show how a single NO_X /load combination at the common stack can be produced by seven different NO_X/load combinations at the constituent boilers. Based on the absence of a unique NO_X/load correlation at the common stack, the commenter concludes that ''common stack NO_X data cannot be used to characterize the NO_X emissions for individual units.''

EPA's analysis in today's final rule does not presuppose any of the three assumptions identified by the commenter. As discussed above, EPA evaluated the load patterns of individual units on each common stack and found that these load patterns for a given stack were very similar. EPA's load-weighted post-optimization approach first calculates the achievable percent emissions reduction without presumption of a NO_X/load relationship or a particular load pattern and then adjusts the achievable percent reduction based on the annual NO_X/load patterns actually encountered. In effect, this approach takes into account any NO_X/load relationship that may be present without assuming ahead of time that the relationship is present, absent, or takes a particular form.

Finally, it should be noted that for compliance purposes, the NO_X emission limits will usually apply to common stacks, not their constituent units. Under § 75.17, a unit that utilizes a common stack with other units, all of which are required to meet a NO_X emission limit, generally may: separately monitor the duct from each unit to the stack and comply on an individual unit basis; or monitor the stack and comply through an averaging plan with the other units, individually with the most stringent limit for the units, or individually based on an approved method of apportioning the stack emissions rate. Most common stack units use the averaging plan option. In fact, all common stack units analyzed in this rulemaking that are subject to NO_X emission limitations in Phase I are complying through averaging their emissions with the other units in the common stack, not individually. Thus, from a regulatory, as well as a strictly technical perspective, it is appropriate to use common stack emission data to build the model employed in establishing the Phase II, Group 1 NO_X emission limits that will apply to boilers and common stacks.

4. Percentile Used to Define Achievability

Background. For the final step of the analysis, EPA arrayed the estimates of controlled NO_X emission rates that the Phase II units could be expected to achieve when retrofit with LNBs. Separate rank orderings were made for wall-fired boilers and for tangentially-fired boilers. Using these rank orderings, EPA tabulated percentile distributions of achievable annual emission rates for each boiler category (see 61 FR 1452, (Tables 10 and 11)). EPA selected values for the proposed annual emission limitations that, according to these tables, about 90% of the affected units could comply with on an individual basis. It was not necessary that 100% or even essentially all of the affected units be able to comply with the applicable performance standard on an individual basis because of the flexibility offered by two compliance options available to Group 1 boilers: (1) emissions averaging and (2) alternative emission limitations (AELs).

Comments/Analyses. EPA received approximately 5 comment letters (from 3 state agencies representing 2 different states, a regional association of state air pollution control agencies, and an environmental organization) on the percentile used to define achievability.

These commenters said that, given the serious and multifaceted threat NO_X poses to the environment and public health, EPA should set the most effective controls possible within existing authority. According to one state agency, ''the reductions in nitrogen oxide anticipated by the proposed regulation . . . are minimal compared to the amount of NO_X reductions necessary to protect the sensitive aquatic resources of the northeastern United States from further degradation'' (see docket item IV–D–25, p. 3). A regional association of state air pollution control agencies said, ''(While) EPA's authority to promulgate emission limits derives in this instance from a section of the CAA chiefly concerned with addressing acid deposition . . . EPA's proposal should be viewed in light of the much more significant emissions reductions needed to rectify other serious air quality and public health problems that are also associated with NO_X emissions, including fine particulate pollution, ozone smog, regional haze, and the eutrophication of aquatic ecosystems.'' (See docket item IV–D–46, p. 2.) They urged EPA to base its revised emission limitations for Phase II, Group 1 boilers on a lower threshold than 90% of the affected population in light of the flexibility afforded by the emissions averaging and AEL compliance options (see docket items IV–D–46, p.6; IV–D–63, p.7; and IV–D–25, pp. 5–6).

The Offices of the Attorney General of two northeastern states and an environmental organization said that EPA's proposal would allow excessive NO_X emissions for Group 1 boilers since, according to the RIA for the proposed rule, ''less than half the potentially affected sources may be required to implement new controls.'' (See docket items IV–D–25, p. 5; IV–D–74 p. 4; IV–D–63, pp. 6–7.) Two of these commenters recommended setting Phase II, Group 1 emission limitations at 0.41 lb/mmBtu for wall-fired boilers and 0.35 lb/mm/Btu for tangentially fired boilers, which would increase NO_X

reductions from the Group 1 emission revisions by 57% and would make the emissions averaging provision environmentally neutral (see docket items IV–D–63, pp. 6–7 and IV–D–74, pp.4–5).

No commenter said that EPA's target of 90% compliance on an individual basis was too low. As discussed in the previous sections, however, some commenters disagreed with the technical methods EPA used to develop the percentile distributions of achievable annual emission limitations for Phase II, Group 1 boilers and, as a result, believe the proposed emission limitations are too low. One commenter said EPA should encourage the optional use of AELs or emission averaging plans for Phase II, Group 1 boilers (see docket item IV–D–57, p. 3). Other commenters (but none of the 15 state agencies or associations who commented on the rule proposal) predicted an increase in the number of AEL applications to be filed with state agencies (see, for example, docket item IV–D–31, p. 2).

On the other hand, a regional association that has provided technical expertise to its 8 member states and served as a forum for coordinating region-wide air quality management practices for over 25 years said, ''Experience from reducing NO_X emissions from coal-fired boilers in the Ozone Transport Region (OTR) * * * solidly support[s] EPA's finding that the revised emission limits for Phase II, Group 1 boilers * * * are highly cost-effective, meet the statutory requirements of Section 407, and can be achieved by the vast majority of affected boilers.'' (See docket item IV–D–46, p. 2.) Corroborating this view is the testimony at the public hearing on EPA's rule proposal by the principal engineer for environmental affairs of the largest utility in New England. Based on his experience in retrofitting six coal-fired units that are achieving the proposed NO_X emission rates, he stated that his utility's initial reaction in 1989–1990 to NO_X control requirements ''was virtually identical to the reaction that we're getting from the midwestern utilities and the southern companies now.'' He added that his utility had believed NO_X control ''was frighteningly expensive, it was far more money than it was worth, and our reaction at that point, knowing that we would certainly have to do some controls, was essentially to turn loose the engineers and operators and let them * * * find better ways to do this. The bottom line was that we found that the harder that we looked, the cheaper the controls got. Our final compliance costs are about a fifth of what we thought they would be going into this * * * and we were very pleasantly surprised.'' (See docket item IV–F–1, pp. 7–9.)

Response. As discussed in section I.B.2 of this preamble, EPA is fully cognizant that recent acid deposition and ozone modeling studies show that substantial additional NO_X reductions, even beyond the levels in the rule proposal, are needed to mitigate against the multiple adverse effects of NO_X on human health and the environment, particularly since national NO_X emissions are projected to begin increasing after 2002. On balance, EPA has decided in the final rule to define a reasonably achievable emission limitation as one that 85 to 90% of the units subject to the limitation are projected to meet on an individual unit basis. On one hand, the Agency recognizes that the ability of units to comply by averaging their emissions will increase further the percentage of units that will be able to comply without seeking an AEL. Because almost six times as many units are subject to NO_X emission limitations in Phase II as in Phase I, the opportunities for compliance through averaging will be generally much greater in Phase II. In adopting the initial NO_X emission limitations for Group 1 boilers under section 407(b)(1), EPA selected limitations that about 90 percent of the units were projected to meet on an individual unit basis. In light of the significantly greater opportunities for averaging in Phase II, EPA maintains that the approach of setting Phase II emission limitations targeting a somewhat lower (85 to 90%) individual-unit achievement level is justified. On the other hand, EPA does not want to select emission limitations that would lead to overuse of the AEL compliance option, which is intended primarily for units with very high uncontrolled emission rates or units that are otherwise unusually difficult to retrofit with LNBs. The RIA for this final rule estimates the average cost to a utility for testing, monitoring, and documentation associated with an AEL application will run about $225,000, but this cost may vary considerably by utility and for different states (see docket item V–B–1, Exhibit 6–6). One commenter estimated each AEL application will cost ''the Company in excess of $300,000 in testing and analytical expenses'' (see docket item IV–D–23, p. 6), although the commenter did not say whether his utility imposes additional internal requirements to justify filing with the permitting authority for a special (higher) emission limitation. As discussed below, the RIA projects that AELs will be used by less than 10% of Phase II boilers.

The Agency has developed Tables 5 and 6 displaying the percentage of Phase II, Group 1 units, by boiler category that are projected to achieve various annual average emission limitations when retrofit with LNBs. The values EPA has selected to promulgate as revisions to the Group 1 emission limitations are in bold print. In response to comments stating that the proposed 90 percent passing threshold in the proposed rule was too conservative, EPA has decided to set the emission limit for Phase II, Group 1 and Group 2 boiler types based on the emission level that 85 to 90 percent of the affected boilers can individually meet. Thus, EPA considers an emission limit to be reasonably achievable if 85 to 90 percent of the units of the particular boiler type are projected to meet the emission limit. Therefore, in the absence of unique, countervailing circumstances, EPA has generally selected as the Phase II, Group 1 or Group 2 emission limit the emission rate with an individual-unit achievement level that is between 85 and 90%. On this basis, EPA adopts revised Phase II, Group 1 emission limits of 0.46 lb/mmBtu for Phase II wall-fired boilers and 0.40 lb/mmBtu for tangentially fired boilers.

TABLE 7.—PERCENTILE OF PHASE II WALL-FIRED BOILERS ACHIEVING EMISSION LIMIT

Emission level (lb/mmBtu)	Percent of boilers meeting emission level
0.48	96.0
0.47	91.9
0.46	88.3
0.45	85.0
0.44	83.2
0.43	78.0

TABLE 8.—PERCENTILE OF PHASE II TANGENTIALLY FIRED BOILERS ACHIEVING LIMIT

Emission level (lb/mmBtu)	Percent of boilers meeting emission level
0.43	98.2
0.42	98.2
0.41	95.7
0.40	91.4
0.39	78.1
0.38	67.6

The RIA for this final rule also projects the number of affected units for which utilities are apt to select the AEL compliance option. The projection models a scenario where evaluation of emissions averaging opportunities is not a pre-requisite for an AEL (a true assumption). The RIA predicts that, with the annual emission limitations EPA is promulgating in this final rule, AELs are likely to be sought for approximately 42 Phase II, Group 1 boilers, representing 7% of the affected population (see docket item V–B–1, Exhibit 7–5).

B. Group 2 Boiler NO_X Emission Limits

1. Cost Comparability and Its Basis

Section 407(b)(2) the Act requires EPA to set Group 2 boiler NO_X emission limits based

> on a degree of emission 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 oxide controls set pursuant to (section 407)(b)(1). 42 U.S.C. 7651f(b)(2).

The Act does not define the term ''comparable'' or specify the appropriate method of comparing ''costs''. In the proposal, EPA stated that it believed that the terms ''comparable'' and ''cost'' were ambiguous, and, therefore, EPA consulted the legislative history of section 407(b)(2). Based on the legislative history, EPA's proposal interpreted ''comparable'' to mean ''similar but not necessarily equal'' and used cost-effectiveness ($/ton of NO_X removed) as the basis for conducting cost comparisons. 61 FR 1460. EPA interpreted the comparable-cost provision in section 407(b)(2) to require that the cost-effectiveness of applying NO_X controls to any Group 2 boiler population be comparable to the cost-effectiveness of applying LNBs to the Group 1 boiler population . EPA also took account of the other factors (e.g., ''costs and energy and environmental impacts'') listed in section 407(b)(2) by, *inter alia,* determining whether the cost impact to ratepayers (in mills/kWhr) of Group 2 boiler NO_X controls is similar to the cost impact (in mills/kWhr) of Group 1 boiler LNBs.

Comment/Analyses: EPA received 7 comments (from 3 utilities, 1 State, 1 utility associations, and 2 environmental groups) on the interpretation and implementation of the comparability requirement in section 407(b)(2).

Some utility commenters believe that the term ''comparable'' is not ambiguous as used in the statute because it has a common dictionary meaning of ''equivalent'' or ''similar.'' These commenters argue that, because ''comparable'' has a commonly understood meaning, there is no reason to consult legislative history. Other utility commenters believe that ''comparable'' should be interpreted to mean ''equal to'' or ''less than or equal to.'' Other commenters cite the common dictionary definition of the term ''comparable'' and maintain that the term is inherently vague. These commenters believe that EPA's reliance on the legislative history is proper since the common meaning of the term ''comparable'' is ambiguous, that the legislative history cited by EPA is the only reference in the legislative history addressing what Congress meant by the term ''comparable,'' and that the legislative history supports EPA's interpretation.

EPA notes that, according to the Webster's Third New International Dictionary (Springfield, Massachusetts, 1981), the term ''comparable'' is defined as: (1) ''Capable of being compared''; (2) ''suitable for matching; coordinating; or contrasting: EQUIVALENT, SIMILAR....syn see LIKE.'' Only the second definition appears to be relevant in the context of section 407(b)(2). According to the same dictionary, ''similar'' means ''having characteristics in common: Very much alike: COMPARABLE'' while ''equivalent'' means ''equal in force or amount.'' As further explained (under the dictionary's discussion of ''like''): ''COMPARABLE indicates a likeness on one point or a limited number of points which permits a limited or casual comparison or matching together.'' In short, one set is ''comparable'' to another set if the two are equal *or* if they are ''similar'' to each other without being identical. Therefore, ''comparability'' does not require ''equality,'' and the degree to which ''comparable'' sets must be ''similar'' to each other is unclear under section 407(b)(2) and is a matter of administrative judgment.

Some commenters further believe that section 407(b)(2) of the Act states that what should be compared is the ''cost'' (allegedly mills/kWh) of ''controls'' such as LNBs, not the ''cost-effectiveness'' ($/ton of NO_X removed) of those controls. These commenters argue that cost-effectiveness is only appropriate when the ''cost'' to be measured is the cost of attaining emission reductions and that the plain meaning of section 407(b)(2), supported by the legislative history, is that the Administrator is required to compare ''cost,'' not ''cost-effectiveness,'' as the basis for setting Group 2 emission limitations.

Other commenters state that the plain meaning of section 407(b)(2) requires that the ''degree of reduction'' on which EPA bases Group 2 emission limitations must be comparable to the costs of controls set under section 407(b)(1) for achieving reductions from Group 1 boilers. According to these commenters, the only way to determine and to compare costs for achieving reductions is to use a measure of cost-effectiveness. Commenters also state that the legislative history also clearly indicates that ''cost-effectiveness'' is the appropriate measure of comparing costs in setting Group 2 emission limitations.

EPA notes that in appendix B of the April 13, 1995 NO_X rule (and the March 22, 1994 rule that was remanded to EPA), EPA explained that cost-effectiveness ($/ton of NO_X removed) was to be used as the basis for determining the comparability of Group 2 boiler NO_X controls to Group 1 boiler LNBs. As stated in Appendix B:

> In developing the allowable NO_X emissions limitations for Group 2 boilers pursuant to subsection (b)(2) of section 407 of the Act, the Administrator will consider only those systems of continuous emission reduction that, when applied on a retrofit basis, are comparable in cost to the average cost in constant dollars of low NO_X burner technology applied to Group 1, Phase I boilers, as determined in section 3 below. 60 FR 18776 (1995); *see also* 59 FR 13578 (1994).

Section 3 of Appendix B is titled ''Average Cost-Effectiveness for Low NO_X Burner Technology Applied to Group 1, Phase I Boilers,'' and the only cost-calculation methodology presented in the appendix is one for calculating the average cost-effectiveness of LNBs. Both annualized capital costs and annual operating and maintenance costs are to be reflected in the cost-effectiveness calculations. The commenters now opposing using cost-effectiveness as the basis for applying the comparable-cost requirement for setting Group 2 emission limitations did not challenge this approach in appendix B, either as part of their appeal of the March 22, 1994 rule or with regard to the repromulgation of the appendix (with minor changes) as part of the April 13, 1995 rule. It is difficult to see how these commenters can now argue that the language of section 407(b)(2) ''clearly'' bars the use of cost-effectiveness. Moreover, inconsistent with their claim that EPA must compare ''cost'' not ''cost-effectiveness,'' some of these commenters also argue EPA must follow, and cannot legally change in this rulemaking, the appendix B procedures, which are grounded on the comparison of cost-effectiveness. (See, for example, docket item IV–D–65, p. 80–95.)

Response: The Agency continues to believe that the statutory terms, ''comparable'' and ''cost'' are ambiguous, and maintains that its interpretation of ''comparable'' as ''similar but not necessarily equal'' and its decision to compare cost-effectiveness are consistent with a reasonable interpretation of the statutory language and the legislative history. Therefore, the final rule uses a cost comparability test similar to that in the proposed rule. However, in response to commenters' concerns, EPA has modified its specific criteria for determining whether control systems have comparable cost-effectiveness. In the proposed rule, EPA considered a control option for Group 2 boiler type to be ''comparable'' in cost-effectiveness to LNBs on Group 1 boilers if: the cost-effectiveness range for the Group 2 control option fell within the range (excluding outliers) for Group 1 LNBs; and the median cost-effectiveness value for the Group 2 control option was within 50% of that for the Group 1 LNBs. As discussed below, in the final rule EPA considers Group 2 control options to be ''comparable'' if the median cost-effectiveness of the Group 2 control option used to meet the Group 2 emission limitation: (1) Does not exceed by more than one-third the median overall cost-effectiveness of Group 1 controls used to meet the Group 1 emission limitations; and (2) does not exceed the median cost-effectiveness of Group 1 controls for either of the two types of Group 1 boilers, i.e., dry bottom wall-fired boilers and tangentially fired boilers regulated pursuant to section 407(b)(1). Additionally, the 90th percentile cost-effectiveness value of the Group 2 control option should not exceed the 90th percentile value cost-effectiveness value of Group 1 LNBs.

EPA believes that the approach used in the analysis to support the final rule is a reasonable interpretation of the term ''comparable'' in the context of section 407(b)(2). Where sets of values are being compared, EPA maintains that it is logical to consider the distributions, not just the medians, of the sets of values. Comparisons based solely on measures of central tendency (e.g., medians) neglect important information (e.g., about the range and shape of the distributions) that is relevant to determining whether the sets of values are comparable. EPA notes, with regard to the cost-effectiveness of NO_X controls under section 407(b)(1), that: the costs reported by utilities for LNB applications to Group 1 boilers ranged from $37 to $2,625 per ton of NO_X removed; the median cost-effectiveness of Group 1 boilers as a whole is $413 per ton of NO_X removed; and the medians of cost-effectiveness of LNBs applied to dry bottom wall-fired boilers and tangentially fired boilers (which boiler types each make up about 50% of the Group 1 boiler population) are $270 and $611 per ton of NO_X removed, respectively. Particularly given this wide disparity in the cost-effectiveness of Group 1 boiler controls, EPA considers the above criteria used in the final rule to be a reasonable interpretation of the meaning of ''comparable'' in the context of evaluating the cost-effectiveness of various Group 2 NO_X control methods.

This approach is consistent not only with the meaning of the statutory term, ''comparable,'' but also with the legislative history of section 407(b)(2). The Conference Report for the bill that became the Clean Air Act Amendments of 1990 did not itself address the meaning of ''comparable'' but the report explicitly ''incorporated'' a portion of the December 20, 1989 Senate committee report for an earlier version of that bill, which discussed comparability. The Conference Report explained :

> 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), A Legislative History of the Clean Air Act Amendments, 103d Congress, 1st Sess. at 1794 (November 1993).

The relevant portion of the Senate report discussed the difficulty and cost-effectiveness of reducing NO_X emissions from cyclone, wet bottom, and stoker boilers, explaining that the Senate bill was 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 methodology 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) (emphasis added) , A Legislative History at 8672–73.

Some commenters noted that the Senate report accompanied an earlier version of the bill amending the Clean Air Act Amendments and that version of the bill did not include the ''comparable cost'' language in section 407(b)(2). However, because the Conference Report expressly incorporated the Senate report, which is the only legislative history concerning the term ''comparable'', EPA maintains that the Senate report is relevant. The legislative history also indicates that, at the time, the cost of LNBs was estimated to be about $150 to $200 per ton of NO_X removed. *Id.* at 8810. The fact that a cost-effectiveness value for SCR that was, at $600/ton, 300–400% greater than the cost of LNBs was expressly considered to be ''comparable'' to LNB costs, supports the conclusion that the criteria used in the comparability analysis in today's final rule is a reasonable approach to implementing section 407(b)(2).

The Agency also disagrees with those commenters that argued that ''cost'', rather than ''cost-effectiveness,'' is the appropriate measure of cost under section 407(b)(2). The language of section 407(b)(2) is ambiguous on this point, and EPA maintains that interpreting that section to require that costs be measured in terms of cost-effectiveness is reasonable and consistent with the legislative history.

Section 407(b)(2) states:

> The Administrator shall base (Group 2 emission) rates on a degree of emission 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 oxide controls set pursuant to (section 407)(b)(1).* 42 U.S.C. 7651f(b)(2) (emphasis added).

The meaning of the crucial phrase on cost-comparability (i.e., the phrase, ''which is comparable to the costs of nitrogen oxide controls'') is vague because there are two plausible antecedents in section 407(b)(2) for the pronoun, ''which'': (1) The ''degree of reduction'' (i.e., the level of removal of NO_X); or (2) the ''retrofit application of the best system of continuous emission reduction'' (i.e., the Group 2 control method). EPA maintains that the use of the conjunction, ''and'', at the beginning of the phrase suggests that the cost-comparability phrase modifies the ''degree of reduction''. If the phrase instead modifies the ''best system of continuous emission reduction'', the statute could have been written, without the conjunction, to read: ''the retrofit application of the best system of continuous emission reduction, taking into account available technology, costs and energy and environmental impacts'', which is ''comparable * * *'' (*id.*). However, because of the general grammatical awkwardness of the entire sentence, EPA does not consider this analysis to be dispositive .

The conclusion that the meaning of ''cost'' is ambiguous is supported by the fact discussed above, that various commenters argued that the ''plain meaning'' of section 407(b)(2) supports two mutually inconsistent interpretations of the cost-comparability provision. On one hand, some commenters argued that the ''plain meaning'' of the provision is that the cost in mills/kwh of Group 2 control methods must be comparable to the mills/kwh cost of Group 1 control methods, i.e, that the cost-comparability phrase modifies ''best system of continuous control reduction'' (see docket item IV-D–65, p. 75, note 172)[17]. On the other hand, some other commenters argued that the cost-comparability phrase clearly modifies ''degree of reduction'' and that the only way to compare the costs of reductions is by analyzing cost-effectiveness, i.e., \$/ton of NO_X removed. (See docket item IV-D–63, p. 15–16). In supporting their interpretation, these latter commenters make the plausible claim that the words ''nitrogen oxide controls set (pursuant to [section 407)(b)(1)'' refers to the NO_X emission limitations established under section 407(b)(1), rather than to Group 1 NO_X control methods (i.e. LNBs applied to Group 1 boilers). These commenters argue that it is the emission limitations, not the control methods, that are set under section 407(b)(1). *See National Mining Association* v. *EPA*, 59 F3d 1351, 1362 (D.C. Cir. 1995) (holding that the word ''controls'' refers to ''governmental regulations''); *see also* 42 U.S.C. 7511b(e)(1)(A) (section 183(e)(1)(A) of the Act, which defines ''best available controls'' as the ''degree of emissions reduction'' that the Administrator determines meets certain requirements) and *compare* 42 U.S.C. 7511b(b)(3) and (4) (referring to ''best available control measures'').

However, this latter claim is not essential because, even if NO_X ''controls'' set under section 407 (b)(1) refers to LNBs applied to Group 1 boilers, the cost-effectiveness interpretation of the provision is still reasonable. The only way to determine if the ''degree of reduction'' achieved with a prospective Group 2 NO_X control method is comparable to the costs of LNBs applied to Group 1 boilers is to take into account both the level and the dollar cost of achieving NO_X reductions and, therefore, analyze the cost-effectiveness of Group 1 and Group 2 control methods. If Group 1 and Group 2 control methods were compared only on the basis of capital costs (dollars per kilowatt) or total annualized costs (mills per kilowatt hour), then the ''degree of reduction'' achieved with the NO_X control methods would be ignored. Under that approach, if taken to its logical extreme, section 407(b)(2) could then be interpreted to allow EPA to set emission limits based on specific control systems with little or no regard for the NO_X removal capabilities of the control systems.

In short, the fact that section 407(b)(2) requires ''cost'' to be comparable is not dispositive. Based on the context in which the term is used, ''cost'' can reasonably be interpreted to refer to cost-effectiveness. *See, e.g., API* v. *EPA*, 660 F2d.954, 962–64 (4th Cir. 1981) (interpreting statutory language in 33 U.S.C. 1314(b)(4)(B) requiring consideration of the ''cost and level of reduction'' of pollutants to require EPA to set standards based on comparisons of cost-effectiveness).

Having concluded that the language on cost-comparability in section 407(b)(2) is ambiguous, EPA considered the legislative history. The legislative history is consistent with the use of cost-effectiveness as the measure of cost in determining cost-comparability. As discussed above, the Conference Report for the Clean Air Act Amendments of 1990 explained that the Group 2 emission limitations 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 at 344 (emphasis added).

Further, the relevant portion of the Senate report, which is referenced in the Conference Report, specifically discussed ''the decreasing costs for selective catalytic reduction'', one method of NO_X reduction, stating:

> 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 methodology followed by EPA. *This is comparable to the cost of conventional control methods* like low-NO_X burners and thermal de-NO_X. Senate Rep. No. 101–228 at 332–33 (emphasis added).

In short, both the Conference Report, and the Senate committee report that it incorporated, expressly state that ''cost comparability'' was viewed in terms of costs per ton of NO_X removed. Indeed, in virtually every discussion in the legislative history (including those instances cited by commenters) concerning the cost of NO_X control methods, the data on the cost of any specific control method—whether LNBs, SCR, or any other method—was presented solely in terms of dollar cost per ton of NO_X removed[18]. *See, e.g.,* Senate Rep. No. 101–228 at 332–33 and 470; A Legislative History at 2546–7 (House floor debate, submissions by Congressman Waxman); Senate Rep. No. 1894, 100th Cong., 1st Sess. at 74, (November 20, 1982); A Legislative History at 9512 (report on predecessor legislation).

The Agency notes that, when legislative history is considered, the Conference Report and the Senate committee report are entitled to greater weight than floor statements of individual legislators. EPA examined the floor statements addressing section 407(b)(2) and earlier versions of the section and finds that these statements either support the Agency's use of cost effectiveness under the cost comparability test or are, at most, ambiguous on this point.

For example, in the Senate debate on the Conference Report, Senator Burdick (chairman of the Senate Committee on Environment and Public Works) stated that

> Cyclone and wet-bottom boilers may be required to reduce nitrogen oxide emissions

[17] EPA notes that these same commenters support the Appendix B methodology, which establishes cost-effectiveness as the basis for comparing Group 1 LNBs to Group 2 NO_X control systems.

[18] It appears that the only exception, where dollars rather than dollars per ton of NO_X removed were discussed, was a reference to the total dollar cost of all NO_X control methods. A Legislative History at 977, 989.

only if the *costs of such reductions are as cost-effective as reductions from installation of low NO_X burners* on other types of boilers. . . This provision is carefully worded to make *cost considerations the determinative factor in consideration of NO_X reductions* from cyclone and wet-bottom boilers. A Legislative History of the Clean Air Act Amendments of 1990 at 778 (emphasis added).

In the same debate, Senator Baucus, subcommittee chairman and floor manager for the Act, entered a statement into the record explaining that

These (section 407(b)(2)) emissions limits must be based on available technology, costs and energy and environmental impacts for the best system of continuous emission reduction and must be *comparable in cost to the limits set for the Phase I units. Id.* at 1039 (emphasis added).

In both of these statements the Senators indicated that what is being compared is the cost of Group 2 reductions or emission limits (i.e. cost-effectiveness of Group 2 NO_X control methods) with the cost of Group 1 reductions or emission limits (i.e. the cost-effectiveness of LNBs used to meet the Group 1 limits).

Other floor statements are more ambiguous, referring both to ''costs'' of control methods and to ''cost-effective'' control methods. For example, an earlier statement by Senator Baucus explained that if the ''costs of SCR were to remain in excess of'' LNB technology, SCR would not be ''required for cyclones'', but he also noted that ''we do not know what the most effective controls will be at the end of the century.'' A Legislative History at 7137. *See also id.* at 6168 (another statement by Senator Baucus). Senator Lott, who introduced the bill amendment that became section 407, stated that under the amendment, ''utilities will not be forced to install unreasonably expensive equipment'' and NO_X emission limits will be based on ''the application of low NO_X burner technology, a much more reasonable and cost-effective method proven to successfully achieve significant NO_X reductions''. *Id.* at 6168. Senator Lott added that the amendment allows flexibility to comply ''in the most cost-effective manner''. *Id.* Similarly, Senator Chafee asserted that the provisions that became section 407 would not force the installation of ''unreasonably expensive equipment'' and added that ''more reasonable and cost-effective methods have proven to be successful in achieving significant NO_X reductions.'' *Id. See also id.* at 7181 (statement of Senator Bumpers that Senate bill allows ''utilities the freedom to choose the most cost-effective strategies to control'' SO_2 and NO_X).

Finally, the Agency notes that some commenters argued that section 407(b)(2) must require measurements of ''cost'' rather than cost effectiveness because the House version of the section 407 NO_X provisions expressly used the term ''cost effective'', which term was not included in the final bill. House Bill 3030, passed May 23, 1990, required the Administrator to set NO_X emission limitations to achieve in 2000 2.5 million tons of reductions below the 1989 projected emissions and authorized adjustment of the limitations to increase total reductions to up to 4.0 million tons if the reductions are, *inter alia,* ''cost effective.'' A Legislative History at 2275–76. The adjustment could apply to cyclone or wet-bottom boilers if the emission reduction methods for such boilers were found to be ''as cost effective'' as the application of low NO_X burners to wall-fired or tangentially-fired boilers. *Id.* at 2277. The Agency does not consider this difference in language between the House bill and the final bill persuasive in interpreting the cost-comparability requirement of section 407(b)(2). As discussed above, the context in which the term ''cost'' is used in the final version of section 407(b)(2) is reasonably interpreted to require the comparison of the cost effectiveness of Group 1 and prospective Group 2 control methods.

In summary, EPA believes that the interpretation in the proposed rule for the meaning of ''comparable'' and ''cost'' is reasonable and consistent with both the language of the statute and the legislative history. EPA therefore applies, in today's final rule, the cost-comparability requirement of section 407(b)(2) by comparing the cost-effectiveness (in \$/ton of NO_X removed) of Group 2 control technologies and Group 1 LNB installations, which is the only measure that incorporates both total cost and NO_X reduction performance. The next section discusses EPA's methodology for determining what Group 2 boiler NO_X controls are ''comparable'' in cost-effectiveness to Group 1 LNBs.

EPA notes that in addition to the cost-comparability requirement, section 407(b)(2) requires that, in setting Group 2 emission limitations, the Administrator ''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 apply and balance these factors. In particular, the Administrator must decide how to evaluate the factors and what relative weight to give each factor. While the Administrator's determination of cost-comparability is based on cost-effectiveness, the Administrator did not ignore cost as measured in mills per kilowatt-hour of generation. In giving meaning to the requirement to take ''account of . . . costs and energy. . . impacts'' (42 U.S.C. 7651f(b)(2)), EPA considered the impact of mills/kWh-of-generation costs of Group 2 NO_X emission limitations on electricity consumers.

2. Cost Comparison Methodology

EPA must develop data on the costs for LNB retrofits of the Group 1 boiler categories (i.e., dry bottom wall-fired and tangentially fired boilers) so that a comparability of retrofit costs between LNBs and NO_X controls for Group 2 boiler categories can be established. The procedures originally to be used in developing these LNB costs were outlined in Appendix B of the Phase I NO_X rule. Appendix B also required that the comparability of retrofit costs between LNBs and NO_X controls for Group 2 boilers be established on the basis of cost-effectiveness of NO_X control technology expressed in \$/ton of NO_X removed. For the LNB retrofits in Phase I, appendix B procedures called for developing curves depicting capital cost as a function of boiler size, computing an average capital cost, characterizing operation and maintenance costs, and computing an average cost effectiveness in \$/ton of NO_X removed based solely on the population that reported LNB costs to EPA.

In support of the proposed rule, EPA prepared a report (see docket item IV–A–1) that compiled available cost and performance data from the Phase I LNB retrofits, developed curves to explain the dependence of capital cost of these retrofits on boiler capacity, and developed annualized costs for these retrofits. EPA then applied these costs to the whole Group 1 boiler population, developed a distribution of Group 1 cost-effectiveness values, and compared that distribution to the distribution of NO_X control cost-effectiveness for each Group 2 boiler/NO_X control combination. The distribution of NO_X control cost-effectiveness for each Group 2 boiler/NO_X control combination was developed in a similar way to the Group 1 cost-effectiveness distribution. In the proposed rule, EPA considered Group 2 controls comparable if (1) the upper-end of their cost-effectiveness range (in \$/ton removed) was within the upper-end of the of cost-effectiveness range of Group 1 boilers with LNBs; and (2) their median cost-effectiveness value was within 50% of the median cost-effectiveness value for Group 1 boilers with LNBs. The methodology used by EPA has been criticized by commenters because it deviates from the appendix B procedures, which imply a comparison of averages rather than distributions.

Comments/Analyses: Some commenters believed that EPA's approach of comparing distributions is contrary to appendix B and allows for very wide ranges in cost due to boiler-specific influences such as utilization and uncontrolled NO_X emissions. These commenters believed that the comparison should be made using ''typical'' values for utilization and uncontrolled NO_X emissions and deriving a single number for the cost-effectiveness of Group 1 LNBs and each Group 2 boiler/NO_X control combination. The commenters, however, did not provide any insight as to how the cost-effectiveness values will be compared under this alternative approach, stating only that in order for the costs to be comparable they must be equal.

Some commenters believed that EPA's attempt to modify the Appendix B cost comparison methodology is illegal because EPA has failed to meet the legal requirement to justify abandoning it. They also stated that the appendix B analysis is valid (and should be used) because it produces results consistent with earlier estimates of LNB costs. However, EPA notes that these commenters have not supplied information addressing the accuracy of appendix B.

Numerous comments supporting EPA's departure from the appendix B approach have also been received. These comments stated that EPA's improvement of its cost-comparison methodology is legal and justified.

Response: Although appendix B implies that the cost-effectiveness comparisons of Group 2 boiler/NO_X control technology combinations to Group 1 LNBs will be done by single point comparisons, it does not provide a precise methodology for how these comparisons will be conducted. In addition, commenters supporting the appendix B approach provided no insight into how they believe the comparisons should be conducted. Thus, EPA's proposed methodology is the only methodology presented to date that explains how to determine whether Group 2 boiler/NO_X control technology combinations are ''comparable'' to Group 1 boilers with LNBs. However, in light of the negative comments received, EPA has decided to re-evaluate its cost-effectiveness comparison methodology.

Some commenters argued that EPA's departure from the appendix B procedures was illegal and resulted in erroneous conclusions and an overstatement of wall-fired and tangentially fired LNB retrofit costs experienced by the utilities. In order to respond to these comments, it is necessary to review the methodology used by EPA in estimating LNB costs, show the extent to which this methodology adheres to appendix B procedures, and examine the appropriateness of the digressions from appendix B taken in EPA's methodology.

i. Appendix B Methodology

To follow the procedures specified in appendix B, EPA compiled a database of Phase I LNB retrofit costs and NO_X reductions reported by the utilities. (Hereafter this database will be referred to as the ''cost database.'') EPA compiled cost and performance data on 56 Phase I boilers including 35 wall-fired boilers and 21 tangentially fired boilers. These data include boiler-specific details on capital and O&M costs and actual or projected annual NO_X reductions. This database can be found in docket item IV–A–1.

Appendix B required that, using the capital costs in the cost database, capital cost curves or equations be developed for dry bottom wall-fired and tangentially fired boilers. It further required using these curves or equations to develop a weighted average capital cost for the Phase I dry bottom wall-fired and tangentially fired LNB retrofits, with the weighting factor being the unit gross nameplate capacity (in MW) as reported in the NADB.

Following the appendix B requirements, EPA developed capital cost equations. It should be noted that the importance of the derived capital cost equations is that they represent characteristic values of and trends in capital cost that can be anticipated from retrofits of each boiler firing type. The capital cost equations can be applied to the much larger population of wall-fired and tangentially fired boilers to arrive at characteristic capital costs of retrofits for the entire population of Group 1 boilers because: (1) The regressions used are good representations of the averages of reported costs (see docket item IV–A–1); and (2) the ranges in the capacities of boilers currently in the cost database (75 to 816 MW for wall-fired and 100 to 936 MW for tangentially fired) are a good representation of the ranges in boiler capacities found in the much larger Group 1 boiler population (30 to 900 MW for wall-fired and 50 to 1000 MW for tangentially fired).

To compute the appendix B average capital cost for wall-fired and tangentially fired LNB retrofits in the cost database, EPA used all of the data from the cost database. This computation yields an appendix B average capital cost of $19.75/kW (in 1990 $s).

EPA notes that the population ratio of wall-fired boilers to tangentially fired boilers in the current cost database is approximately 63/37 percent on a unit basis, whereas the ratio for the entire Group 1 boiler population ratio is approximately 50/50. In fact, tangentially fired boilers in the entire Group 1 population have a combined generating capacity greater than that of wall-fired boilers. Since the average capital cost calculated by the appendix B method is very much dependent on the boilers represented in the database, strictly following appendix B to calculate an average $/kW from the existing cost database would result in the cost of LNB retrofits being biased toward those on wall fired boilers. Thus, the resulting ''average'' cost would not be consistent with the intent of the appendix B requirement to calculate a ton of NO_X reduced-weighted average representative of Group 1 as a whole.

Following the capital cost determination, the procedures described in appendix B require the development of an average cost-effectiveness by annualizing the capital cost using a constant-dollar capital recovery factor (e.g., 0.115 for a 20 year economic life), adding the annualized capital cost to the annual operation and maintenance (O&M) costs for each retrofit, summing the annualized costs for all retrofits, and dividing this sum by the total tonnage of NO_X estimated to be removed each year following the retrofits.

As suggested by appendix B procedures, EPA used a standard annualization factor of 0.115, based on a remaining useful life of 20 years, and an interest rate of 7 percent on borrowed money. These standard assumptions have been used by the Electric Power Research Institute (EPRI) and EPA in developing cost estimates for the utility industry.

The other element of annualized capital, O&M, is a site-specific cost often dictated by the pre-retrofit operating conditions of the boiler, the type of coal used, and the degree of equipment improvements or upgrades necessary to retrofit the LNBs. In fact, utilities that submitted cost data for inclusion in the cost database reported O&M costs ranging from −10 to 59 percent of annualized capital cost for wall-fired boilers and from 0 to 114 percent of the annualized capital cost for tangentially fired boilers. A negative O & M number denotes lower O & M costs after the LNB retrofit. The average O&M costs are 13.5 percent of the annualized capital cost for wall-fired boilers and 23.3 percent of the annualized capital cost for tangentially fired boilers [19].

From the information in the cost database, CEM-measured post-retrofit NO_X emissions, and the above assumptions, EPA calculated cost-effectiveness values for each of the boilers in the cost database. Tables 9 and 10 present boiler-by-boiler results.

TABLE 9.—CALCULATED COST-EFFECTIVENESS FOR WALL-FIRED BOILERS IN COST DATABASE

Plant ID	Reported capital cost ($/kW)	Calculated cost effectiveness ($/ton)
COLBERT 1	25.5	251
COLBERT 2	23.1	347
COLBERT 3	25.6	280
COLBERT 4	20.3	163
COLBERT 5	11	141
COLEMAN 1	9.32	37
COLEMAN 2	9.59	41
COOPER 1	44.05	237
COOPER 2	23.21	149
GASTON 1	4.74	61
GASTON 2	6.77	108
GASTON 3	6.55	121
GASTON 4	6.26	100
BROWN 1	18.65	309
RATTS 1 (*)	12.84	110
RATTS 2	13.16	101
JOHNSONVILLE 7	25.8	178
JOHNSONVILLE 8	29.3	222
JOHNSONVILLE 9	27.9	169
JOHNSONVILLE 10	24.8	159
MITCHELL 1	12.86	163
PULLIAM 7	18.54	161
PULLIAM 8	10.84	155
QUINDARO 2	11.31	250
SHAWVILLE 1	36.05	363
SHAWVILLE 2	44.03	382
SITE C	19.76	149
SITE D–1 (*)	20.72	87
SITE D–2 (*)	18.58	77
SITE D–3	15.66	65
SITE D–4	15.44	74
GREEN RIVER 5	15.93	160
WATSON 4	27.89	263
WATSON 5	35.05	248

[19] Though not used in the appendix B methodology, average O&M costs are used in EPA's final cost comparison methodology.

TABLE 10.—CALCULATED COST-EFFECTIVENESS FOR TANGENTIALLY FIRED BOILERS IN COST DATABASE

Plant ID	Reported capital cost ($/kW)	Calculated cost effectiveness ($/ton)
CONEMAUGH 1 (*)	18.08	1007
CONEMAUGH 2 (*)	17.23	874
BROWN 2	13.65	533
MCDONOUGH 1	54.24	1423
MCDONOUGH 2	34.58	1310
SHAWVILLE 3 (*)	53.91	2436
SHAWVILLE 4 (*)	52.24	2625
YATES 4	16.54	1622
YATES 5	16.54	1391
SITE A–1	[20] 28.69	417
SITE A–2	[20] 28.51	422
SITE A–3	[20] 33.53	500
SITE A–4	[20] 29.56	429
SITE A–5	[20] 28.60	408
SITE A–6	[20] 29.10	423
SITE B–1	16.69	489
SITE B–2	14.73	391
ALLEN 1	8.9	345
ALLEN 3	8.8	312
RIVERBEND 7	10.40	762
RIVERBEND 8	7.78	548

[20] Capital costs have been adjusted to exclude costs associated with major waterwall modifications (see docket item IV–A–9).

Consistent with appendix B, EPA did not consider boilers in Tables 9 and 10 that were not achieving the statutory emission rates (i.e., the boilers marked with (*) in the tables) when determining average cost effectiveness. EPA converted the figures in the tables from 1995 $/ton of NO_X removed to 1990 $/ton of NO_X removed using a cost scaling factor of 0.963. Further, according to appendix B, instead of averaging the individual $/ton to determine an average cost-effectiveness for the population (i.e., Average $/ton = $((\$/ton_{21} + (\$/ton)_2 + . . . + (\$/ton)_n)/n)$, the average cost-effectiveness is determined on a ton-weighted basis, by adding all the dollars and dividing by all the tons (i.e., Average $/ton = $(\$_1 + \$_{22} + . . . + \$_n)/(ton_1 + ton_2 + . . . + ton_1))$. This process yields an appendix B cost-effectiveness of $282/ton of NO_X removed, in 1990 dollars, for the combined wall-fired and tangentially fired LNB retrofits in the cost database. The ranges of cost-effectiveness for the populations of all wall-fired, all tangentially fired boilers as well as the ton weighted average for each boiler type, are shown in Table 11 below.

TABLE 11.—DISTRIBUTION OF COST EFFECTIVENESS FOR THE LNB RETROFITS (1990 DOLLARS)

Population	Average ($/ton)	High ($/ton)	Low ($/ton)
All wall-fired	161	382	37
All tangentially fired	631	2625	312
All boilers	282	2625	37

As shown in the above table, the range in cost-effectiveness for the population of LNB retrofits that reported cost information to EPA is a very wide one which was not anticipated when appendix B was developed or before appendix B was promulgated on April 13, 1995. EPA does not believe that describing this wide distribution by a single number would be appropriate. Doing so, for example, significantly understates the $/ton cost-effectiveness for more than half of the Group 1 population (i.e., the tangentially fired boilers). As illustrated by Tables 8 and 9, the appendix B average of $282/ton does not represent the average cost-effectiveness of controlling Group 1 boilers. The appendix B average is about 50% more than the average for dry bottom wall-fired boilers but almost 60% less than the average for tangentially fired boilers, which account for over half of existing Group 1 capacity.

In fact, the 282 $/ton value determined by appendix B fails to capture any of the reported costs from tangentially fired boilers and falls far short of the average cost-effectiveness of the tangentially fired boiler population, which accounts for over half of the existing Group 1 capacity. This illustrates that the single number approach of appendix B would be inadequate in characterizing the wide distribution of cost-effectiveness of LNB retrofits. A more appropriate Group 1 average cost-effectiveness value is an average derived from the averages of each boiler type in Group 1 weighted by their overall capacities. This approach weighs the $161/ton and $631/ton averages for the wall-fired and tangentially fired boilers by their respective collective capacities in the U.S., resulting in a more representative average Group 1 cost-effectiveness value.

The average cost-effectiveness value, calculated by weighing the boiler type averages by their capacities, is $412/ton and is higher than the median cost-effectiveness determined using EPA's methodology in the proposed rule ($403/ton). The commenters urging EPA to follow the appendix B methodology anticipated that this methodology will yield a lower average cost-effectiveness value (about $200/ton) than EPA's proposed $403/ton. From the above information, their estimate is clearly much lower than the average cost-effectiveness values reported to EPA by utilities. To facilitate comparison, Group 2 boiler NO_X control costs were also developed following the appendix B procedures. Table 12 shows the results of applying the modified appendix B cost-effectiveness calculation methodology to the various boiler and NO_X control technology types.

TABLE 12.—MODIFIED APPENDIX B AVERAGE COST-EFFECTIVENESS OF NO_X CONTROLS

[$/Ton NO_X Removed]

Boiler/NO_X control technology	Average cost-effectiveness ($/ton)
Wall-fired boilers/LNB	161
Tangentially fired boilers/LNB	631
Group 1 boilers/LNB	412
Cell burners/plug-ins	77
Cell burners/non plug-ins	98
Cyclones/gas reburning	480
Cyclones/SCR	544
Cyclones/SNCR	614
Wet bottoms/gas reburning	512
Wet bottoms/SCR	512
Wet bottoms/SNCR	437
Verticals/combustion controls	136
Verticals/SNCR	800

As can be seen from the above table, with the exception of vertically fired boilers applying SNCR, all the average Group 2 boiler cost-effectiveness values are lower than the average tangentially fired boiler cost-effectiveness value. Further, the average cost-effectiveness of each Group 2 boiler/NO_X control technology combination, except SNCR applied to vertically fired and cyclone boilers, is no more than one-third greater than the average cost-effectiveness of all the Group 1 LNB retrofits reported to EPA and is less than the average cost-effectiveness of the tangentially fired LNB retrofits. Therefore, with the exception of SNCR applied to vertically fired and cyclone boilers, all Group 2 boiler/NO_X control technology combinations would be considered comparable in cost-effectiveness to Group 1 LNBs, using the modified appendix B approach. Since the average cost-effectiveness of SNCR applied to vertically fired and cyclone boilers exceeds the average cost-effectiveness of Group 1 LNBs by 80 percent and 39 percent, respectively, these Group 2 boiler/NO_X control technology combinations would not be considered comparable in cost-effectiveness to Group 1 LNBs using the modified appendix B approach.

ii. EPA's Comparison Methodology

Although the modified appendix B approach is presented above, EPA maintains that the methodology used in the proposal, modified in today's final rule, is the better approach. EPA is therefore relying on such final methodology in setting Group 2 emission limitations and adapting, in today's final rule, revisions to appendix B that eliminate the inconsistencies between appendix B and the final methodology. As in the proposal, EPA is taking the approach of removing the inconsistent language in appendix B, rather than restating in appendix B the final methodology described in this preamble.

EPA modified the methodology in the proposed rule due to public comments. These modifications are: (1) Revised capital and O&M costs and NO_X reduction performance for LNBs applied to dry bottom wall-fired and tangentially fired boilers; (2) revised capital and O&M costs and NO_X reduction performance for selective catalytic reduction (SCR) and gas reburning applied to wet bottom boilers; (3) use of year 2000 capacity factors projected by a more sophisticated model (Integrating Planning Model); and (4) use of short-term CEM-recorded uncontrolled NO_X rates in place of NURF emission factors and long-term CEM-recorded NO_X rates. Table 13 reflects the resulting revisions to the cost-effectiveness values presented in the preamble of the proposed rule.

TABLE 13.—DISTRIBUTION OF COST-EFFECTIVENESS OF NO_X CONTROLS

[$/Ton NO_X Removed]

Boiler/NO_X control technology	10th percentile	90th percentile	Median
Wall-fired boilers/LNB	108	1,826	270
Tangentially fired boilers/LNB	286	2,621	611
Group 1/LNBs	142	2,315	413
Group 2/NO_X controls	82	657	407
Cell burners/plug-ins	52	162	91
Cell burners/non plug-ins	69	179	112
Cyclones/gas reburning	357	985	537
Cyclones/SCR	380	1,856	516
Cyclones/SNCR	487	1,193	680
Wet bottoms/SCR	424	657	501
Wet bottoms/gas reburning	413	814	520
Wet bottoms/SNCR	339	733	456
Verticals/combustion controls	95	650	128
Verticals/SNCR	651	1,600	831

The median cost-effectiveness values of each Group 2 boiler/NO_X control technology combination, except SNCR applied to vertically fired and cyclone boilers, are no more than one-third greater than the median cost-effectiveness values of LNBs applied to the Group 1 population and are less than the median values of LNBs applied to tangentially fired boilers. Further, the range in cost-effectiveness observed by the Group 2 boiler/NO_X control technology combinations is within the range in cost-effectiveness of Group 1 LNBs. Therefore, with the exception of SNCR applied to vertically fired and cyclone boilers, all Group 2 boiler/NO_X control technology combinations are considered comparable in cost-effectiveness to Group 1 LNBs.

iii. Conclusions

EPA continues to believe that the original appendix B procedure provides unrepresentative and inappropriate results for the reasons set forth in the proposal, including the draft report cited therein (61 FR 1459). If appendix B is modified to compute averages of the two types of Group 1 boilers separately, this improves somewhat its ability to represent the wide range of cost-effectiveness of the Group 1 boiler types. However, this modification corrects only one of appendix B's shortcomings, and, so, even as modified, appendix B does not provide the most technically sound procedure for determining cost-effectiveness. In contrast, EPA's final methodology is representative of the wide variations in actual and expected costs and corrects the shortcomings of appendix B. EPA notes, in any event, that applying appendix B with modifications to improve its representativeness of the costs of wall-fired and tangentially fired boilers results in the same conclusions as to which Group 2 NO_X control systems are comparable.

3. Retrofit Nature of Group 2 Controls

In support of the proposed rule, EPA, through a contract with an architectural and engineering contractor (A/E), developed cost projections for NO_X control applications to Group 2 boilers. Because these controls need to be integrated with boiler hardware and unit layout, such applications may be lower in cost when applied to new boilers (where boiler and controls can be optimally designed) than when retrofitted to existing boilers (where some of the existing hardware must be modified or removed). Certain commenters raised issues that generically apply to the EPA's cost estimating methodology for all of the Group 2 boiler NO_X control systems. In general, the emphasis of these comments was on whether EPA's estimates considered all of the cost impacts associated with retrofitting these NO_X controls.

Comment/Analyses: One commenter believed that the EPA's estimates did not fully address the magnitude of work involved in the installation of different NO_X control technologies to existing boilers. This commenter also felt that these estimates relied heavily on the information published by commercially motivated equipment suppliers.

EPA notes that a primary consideration in the evaluation of Group 2 boiler NO_X control systems was to fully address the requirements encountered in installing such control systems into existing plant settings. EPA, therefore, developed estimates only where a control technology had a full scale application in the U.S. so that EPA could evaluate its cost estimates against actual retrofit experience. In addition, EPA's estimates included cost items that account for the retrofit nature of the technology applications, including:

(1) Costs accounting for the impacts of incorporating these NO_X control systems on existing plant equipment so that costs pertaining to modifications to the existing equipment and structures are considered, in addition to costs for new equipment and structures, in calculating the capital costs. The report issued by EPA on the Group 2 boiler NO_X control systems contains a list of major equipment, structures, and modifications required for each technology application (see docket item IV–A–4), referred to in this preamble as the ''Group 2 Boiler Study'').

(2) Cost allowances for dismantling and relocation of existing equipment.

(3) Costs for construction and engineering man-hours that reflect the increased labor necessary to perform installation work in an existing plant environment rather than a green field plant site.

(4) Contingency allowances to cover cost increases associated with uncertain site-specific factors. All capital costs were loaded by factors of 15 percent for project contingency and 5 percent for process contingency. An additional 5 percent contingency factor was applied to cover unexpected costs associated with technologies requiring installation of equipment that may impact the existing general facilities.

(5) Costs for modifications to the existing plant equipment that may be typically encountered at some plants for each technology case.

In addition to the above, the costs developed for the various technology cases were verified against several sources of information. Information was not only obtained from equipment suppliers on major pieces of equipment and specialty items, but also verified with price quotations received on most of this type of equipment on other projects by the A/E. Costs for all bulk quantities were developed based on recent experience by the same A/E.

Other commenters alleged that the cost of particular items including ''scope adders'' should be included in EPA's Group 2 boiler NO_X control cost estimates. EPA has considered these comments and concluded that, in general, the ''scope adders'' are costs that are not expected to be incurred in typical retrofits. Instead, to the extent costs included as ''scope adders'' are typical-retrofit costs, they are added to EPA's costs, and, to the extent scope adder costs are not typical-retrofit costs, they are covered by the 5 percent contingency factor in EPA's estimates (for details, see docket item IV–A–4). Additionally, EPA does not include ''scope adders'' in its estimates of Group 1 LNB costs or in its estimates of Group 2 NO_X control costs. Since the ultimate purpose is to compare Group 1 boiler cost-effectiveness to Group 2 boiler cost-effectiveness, EPA's approach provides for a more consistent cost-effectiveness comparison between the two boiler types. Further, by adding contingencies to the Group 2 costs while not adding contingencies to the Group 1 costs, EPA is being conservative in its cost comparisons.

Additionally, EPA notes that all of the boiler modifications required for the technology retrofits were included in the costs presented in the Group 2 Boiler Study. These, for example, include draft fan replacement and reheat system (economizer bypass) addition for SCR systems. Further, EPA's cost estimating methodology in general complied with the procedures listed in the EPRI Technical Assessment Guide (TAG).

Other commenters supported EPA's cost estimates. Two of these commenters (one of which has performed the only retrofit of an SCR to a cyclone boiler) referred to specific retrofit cases for SCR and cell burner combustion modifications where the costs were within the EPA's cost range. One of the commenters indicated that initial cost estimates for retrofit projects could be substantially higher than the actual costs.

Response: EPA believes that the cost estimating procedures used in the Group 2 Boiler Study adequately address the site-specific factors expected to be encountered at various Group 2 boiler sites. Certain sites may have special requirements, such as ''scope adders.'' However, the contingency allowances that have been included in EPA's cost estimates are likely to cover such situations. Additionally, as noted previously, EPA does not include ''scope adders'' in its estimates of Group 1 LNB costs or in its estimates of Group 2 NO_X control costs. Since the ultimate purpose is to compare Group 1 boiler cost effectiveness to Group 2 boiler cost-effectiveness, EPA's approach provides for a more consistent cost-effectiveness comparison between the two boiler types.

In addition, EPA further evaluated its cost estimates to determine the extent to which they reflect the specific requirements imposed by the retrofit nature of the Group 2 boiler applications (as distinguished from applications to new boilers). Table 14 shows the costs associated with the retrofit-specific items for various NO_X control technologies. The cost data presented in this table represent one specific Group 2 boiler application of each technology considered in EPA's evaluation, including combustion controls (non plug-in burners), coal reburning, gas reburning, SCR, and SNCR.

TABLE 14.—PERCENT OF TOTAL ACCOUNTED CAPITAL COSTS RELATED TO RETROFIT ACTIVITY

NO_X technology	Boiler type	Boiler size, (MWe)	Total capital cost, ($/kW)	Retrofit-specific capital ($/kW)	Percent of total capital costs due to retrofit activity (%)
Non plug-in burners	Cell burner	300	18.6	6.4	34
Coal reburning	Cyclone	400	53.7	15	28
Gas reburning	Cyclone	400	15.5	2.4	16
SNCR	Cyclone	400	7.8	1.5	19
SCR	Cyclone	400	40.9	11.1	27

In the above table, total capital cost is the total capital requirement (without the scope adders) for the technology retrofit at the corresponding boiler installation, as shown in the Group 2 Boiler Study. The major retrofit-specific capital costs include the following items:

(1) Boiler furnace wall modifications, coal pipe modifications, sootblower relocations, electrical and control modifications, and relocation of existing equipment for non-plug-ins.

(2) Boiler furnace wall modifications, enclosure modifications, coal handling system modifications, electrical and controls modifications, and demolition of existing equipment for coal reburning.

(3) Electrical and controls modifications, boiler pressure part modifications, and structural modifications for gas reburning and SNCR.

(4) Draft fan replacements, ductwork modifications, electrical and controls modifications, fan modifications, and fly ash handling system modifications for SCR.

As shown in Table 14, a significant portion of the total capital costs developed by EPA cover retrofit requirements.

Further, it should be noted that the above retrofit-specific capital costs include only those items that can be directly associated with the retrofit requirements. For each of these installations, there are other costs included in the total capital cost column in Table 14 that are retrofit-related costs but are not easily separated from non-retrofit-related costs in total estimated costs. These costs are incurred because the work is performed in an existing plant setting and because of the relatively high amount of on-site equipment assembly work required (rather than maximizing assembly in the vendor's shops). Such costs can add significantly to the percentage of total costs that are retrofit-specific costs, and thus the last column in Table 14 likely understates the percentage of total costs that is retrofit-related in EPA's estimates.

In addition to addressing the comments on SCR costs, EPA has conducted an overall analysis to compare its estimated capital costs to actual costs incurred by retrofit applications of these technologies to assure that EPA's overall cost estimates are valid. Through its A/E contractor, which has extensive experience with SCR installations in the U.S. and abroad, EPA has developed a report comparing EPA's SCR cost estimates to actual retrofit costs (see docket item IV–A–16, SCR model validation study). This report shows that EPA's estimates are conservative. Actual costs presented in this report are approximately 20 percent below EPA's estimated costs.

Further support illustrating that EPA's Group 2 Boiler Study accounted for SCR retrofit costs is presented in section III.B.4.iii of this preamble, which addresses the costs of applying SCR to cyclone boilers. That section presents model validation results that show EPA's costs to be conservative when compared to the actual SCR retrofit at Merrimack Unit 2.

Therefore, as in the proposed rule, the analysis supporting the final rule relies on the Group 2 costs developed by the A/E, with extensive experience on SCR installations in the U.S. and abroad, to compare the cost-effectiveness of Group 2 boiler/NO_X control option combinations to Group 1 boiler LNBs. These Group 2 costs adequately address various retrofit cost considerations and, if anything, may overestimate costs in comparison to actual retrofit projects.

4. Group 2 Boiler Size Exemption

Comments/Analyses: The Agency received several comments favoring the proposed exemption provided for small cyclone boilers. The preamble proposed a size threshold of 80 MW for this exemption. Several commenters noted that the proposed rule did not include explicit language to implement the proposed exemption. Commenters also argued that the exemption should be higher, ranging from 100–180 MW. Certain municipal commenters noted that they operated cyclone boilers that were just slightly larger than the proposed 80 MW threshold. One utility argued that EPA has not provided a rationale for selecting the 80 MW cutoff versus a higher cutoff level for the small cyclone exemption. The commenter noted that a review of the boiler population does not show that this is a logical break point, and the commenter could not see any emissions or economic feasibility distinction between units that fall below this level and units operated in the 80–90 MW range. Other commenters suggested a cost-cutoff as an exemption for cyclones if the final rule includes any limit for cyclones.

Certain commenters opposed any exemption for cyclone boilers. The commenters noted that cyclones have large NO_X emissions and should be controlled either through technology or averaging programs. Gas industry commenters disagreed with the exemption because they disagree with EPA's assumption that gas reburning is unavailable for cyclones under 80 MW.

EPA notes that, as shown in EPA's list of Group 2 boilers (see docket item IV-A–4), there are 14 cyclone boilers with a nameplate capacity of 80 MWe or less. There are an additional 19 units that are between 80 and 155 MWe, five of which are owned and operated by municipal utilities.

Response: Pursuant to the Unfunded Mandates Act, EPA notified all municipal utilities (and the appropriate elected officials) with units that are potentially subject to the Phase II NO_X Program. Two of the commenters that specifically commented on the NO_X exemption were municipal utilities, one of which requested that the exemption be expanded to include two cyclone units operated by the utility with nameplate capacity of 90.25 MWe each. The final rule includes an exemption for all cyclones of 155 MWe or less nameplate capacity. The overall impact of this exemption on the emission reductions achieved by the rule is acceptable on balance. On one hand, with the exemption, the cyclone boiler NO_X emission reductions in 2000 are approximately 40,000 tons per year (or about 13 percent) less than without the exemption. On the other hand, the exemption ensures that the NO_X emission limitation for cyclones is applied only to that segment of the cyclone boiler population for which NO_X control systems are comparable in cost-effectiveness to Group 1 boiler LNBs. In addition, the exemption reduces the impact of the rule on municipal utilities with relatively small cyclone units.

The Agency does not believe any exemption beyond this for cyclone boilers is warranted. The Agency believes that the 155 MWe threshold is a rational break point because it results in significant NO_X reductions for many cyclone boilers while providing protection for reducing the impact of the Acid Rain Program on a number of municipal utility units.

For similar reasons, EPA is adopting a 65 MWe exemption for wet bottom boilers. Because the proposed rule treated combustion controls as the appropriate control technology for wet bottom boilers, EPA did not consider any exemption for wet bottom boilers necessary. As discussed above, the final rule is based on the use of either gas reburning or SCR for wet bottom boilers. The Agency notes that the two smallest wet bottom boilers, both of which are under 65 MWe nameplate capacity are both owned by municipal utilities, but the municipal owners did not specifically comment on the proposed limit for wet bottom boilers. However, exempting wet bottom boilers of 65 MWe or less ensures that the NO_X emission limitation for such boilers is applied only to that segment of the wet bottom boiler population for which NO_X control systems are comparable in cost-effectiveness to Group 1 boiler LNBs. The exemption will also reduce the impact of the Acid Rain Program on municipal utilities. The NO_X reductions in 2000 will be about 5,000 tons lower with the exemption but the reductions from wet bottom boilers will still be significant.

Further, since this rule affects utility boilers, not generators, a more meaningful measure of the size cutoff is steam flow at 100% load (measured in lb/hr) instead of generator capacity (measured in MWe). DOE's Form EIA–767, Part III (Boiler Information), Section C (Design Parameters), Item 3 lists each boiler's Maximum Continuous Steam Flow (in thousand pounds/hour) at 100% load. Comparing the Maximum Continuous Steam Flow rating found in Form EIA–767, to generator capacity found in EPA's NO_X boiler database, EPA determined that: the 155 MWe cyclone boiler cutoff can be expressed in lb/hr as 1060 lb/hr at 100% boiler load; and the 65 MWe wet bottom boiler cutoff can be expressed in lb/hr as 450 lb/hr at 100% boiler load. Section 76.7 of the final rule establishes cyclone and wet bottom cutoffs based on the Maximum Continuous Steam Flow at 100% Load of the boiler. Thus, cyclone boilers with a Maximum Continuous Steam Flow at 100% of Load of 1060 lb/hr or less are exempt from the cyclone boiler emission limit set in this rule. Similarly, wet bottom boilers with a Maximum Continuous Steam Flow at 100% of Load of 450 lb/hr or less are exempt from the wet bottom boiler emission limit set in this rule (see docket item IV–B–2, listing cyclones and wet bottoms and their respective generator capacities and Maximum Continuous Steam Flow at 100% Load).

5. Cyclone Boiler NO_X Controls

i. Coal Reburning

In the proposed rule, EPA based the limit for cyclone boilers on the assumption that coal reburning (in addition to SCR) was applicable to all cyclone boilers over 80 MWe and that either coal reburning or SCR could achieve a 50% NO_X reduction efficiency.

Comment/Analyses: Several comments were received by EPA on the feasibility of using coal reburning technology on cyclone boilers. The majority of these comments addressed whether a coal reburning retrofit would be feasible given the existing cyclone boiler design parameters. Other comments were directed to the impacts of this technology on boiler performance or on the balance-of-plant equipment. The potential for reduced precipitator performance, furnace waterwall corrosion, and ability to maintain flame stability at reduced loads were included as specific concerns about the potential impacts of coal reburning.

EPA notes that the adverse impacts of coal reburning on the boiler and balance-of-plant equipment are speculative. The corrosion potential of coal reburning was evaluated and reported for the Nelson Dewey demonstration. This experience does not show any appreciable corrosion as a result of retrofitting coal reburning.

The installation at Nelson Dewey also addressed the potential impact of coal reburning on precipitator performance. Based on long-term experience at this installation, the ash loading at the precipitator inlet increased significantly with no adverse impact on the precipitator outlet emissions and opacity; in fact, there was a slight improvement. Based on the Nelson Dewey experience, it is reasonable to assume that higher ash loadings associated with coal reburning should not have an adverse impact on the performance of existing precipitators. Because of this, the EPA study shows the precipitator upgrade as a scope adder item, which is not expected to be required by most Group 2 boiler installations.

Further, turndown to operating loads below 50 percent was demonstrated at Nelson Dewey. One major factor in facilitating turndown is the number of cyclone burners provided with the boiler. For boilers with a large number of cyclone burners, turndown capability is improved because one or more cyclone burners can be taken off-line during low load operation while the cyclones in service operate at closer to full load conditions. The Nelson Dewey cyclone boiler is equipped with only three cyclone burners, rather than the more usual 4 to 23 burners. Since this installation demonstrated the capability to operate at loads less than 50 percent, it appears that the larger units with more cyclones should not experience difficulty in maintaining their pre-retrofit operating load levels.

Commenters questioned EPA's assumption that the experience from the only operating coal reburning installation at the 110 MW Nelson Dewey Station could be applied directly to all candidate cyclone boilers, especially the larger boilers. Inadequate furnace residence time was raised as the key issue that could make this technology unsuitable for many boilers. Some of these commenters quoted an October 1995 letter from Babcock & Wilcox (B&W) (the technology supplier at Nelson Dewey) to EPA stating that only 30.4 percent of the cyclone boiler population have an adequate residence time for 50 percent NO_X removal, another 15 percent have residence time to support up to 35 percent reduction, and the remaining are mostly unsuitable for coal reburning because of inadequate residence times or expected high unburned carbon levels.

Another commenter, a new supplier of coal reburning that is also a reputable existing supplier of gas reburning, supported the assumptions and results used by EPA in its coal reburning technology evaluation and provided further information on the feasibility of coal reburn. This information is in general agreement with the design basis used in the EPA study. According to this information:

(1) This commenter is in the process of installing coal reburning systems at a 300–MW wet bottom boiler in Ukraine, an industrial 40–MW cyclone boiler in the U.S., and a 240–MW tangentially fired boiler in the U.S. The commenter considers reburning technology commercially viable and is prepared to offer commercial guarantees.

(2) The commenter has conducted and reported a survey of furnace depth for the cyclone boilers in the U.S. The furnace depth is a critical parameter for the reburning feasibility assessment because it affects the mixing of the reburn fuel within the furnace. The commenter reported that there is little increase in the furnace depth for cyclone boilers exceeding a 400 MW rating. The maximum furnace depth for cyclone boilers is reported at 34 feet. There has been successful experience with gas reburning at a furnace depth of 30 feet, and a coal reburning system retrofit on a unit with the same depth is also underway.

(3) The commenter has evaluated reburning feasibility for several large size cyclone boilers and has found sufficient residence time available for reburning application. The typical residence time for these boilers is reported at 0.7 seconds, whereas this commenter's minimum residence time criterion for its coal reburning system is 0.5 seconds.

(4) The residence time criterion may be the main difference between the coal reburning technologies offered by the commenter and B&W. B&W has previously provided a minimum residence time criterion of 1.1 seconds to EPA, which is a far more restrictive requirement than this commenter's criterion of 0.5 seconds.

(5) Based on the above experiences, the commenter does not see boiler size as a limiting factor for the reburning technology.

Response: The coal reburn evaluation presented in EPA's study was based on the experiences with this technology at the Nelson Dewey demonstration project with appropriate adjustments made for the study boiler cases. The results of the Nelson Dewey demonstration were contained in a detailed report by B&W and DOE. In this report, B&W also provided an assessment of the feasibility of this technology, according to which the only feasibility concerns were for the small cyclone boilers (less than 80 MWe).

B&W's October 1995 letter referenced by some commenters was submitted following the completion of EPA's study. This letter appears to be inconsistent with the findings at Nelson Dewey and with the results of analyses B&W reported along with the results of the demonstration. Since B&W did not submit complete details and supporting data regarding its new position, a direct comparison with the information in the original report is not possible.

The concerns raised by some of the commenters are either based on the position taken by one technology supplier (B&W) or are speculative in nature. The information furnished by the new supplier of coal reburning, referenced above, appears to address many concerns regarding coal reburning feasibility on large cyclone boilers. However, because of the inconsistency of the information and experience reported so far with coal reburning, EPA has decided not to rely on this technology to establish emission limitations for cyclone boilers.

Even though there is significant comment supporting the wide availability and proposed achievable reduction performance capability of coal reburning, the main manufacturer of this technology, B&W, raises serious doubts as to its availability for all cyclone boilers and its NO_X reduction performance. At this time, EPA cannot conclude that coal reburning is applicable at 50 percent NO_X reduction on all cyclone boilers. Since SCR and gas reburning have been found to be available control technologies capable of achieving 50% NO_X reduction, EPA does not consider coal reburning technology as one of the best systems of continuous emission reduction for cyclone boilers under section 407(b)(2).

ii. Selective Catalytic Reduction (SCR)

Based on cost analyses conducted by the A/E contractor, EPA proposed an emission limitation for cyclone boilers based on the use of SCR, which was considered comparable to LNB applications on Group 1 boilers, and based the proposed cyclone boiler emission limit on SCR, in addition to coal reburn.

Comment/Analyses: EPA received several comments on the cost of SCR technology applied to cyclone boilers. These comments focused primarily on whether EPA has included all of the new equipment and modifications required for retrofitting SCR to cyclone boilers and whether EPA's cost estimates are comparable to the SCR cost data reported by other stakeholders.

Some commenters believe that EPA underestimated the retrofit cost of SCR by not taking into account some of the necessary SCR system design features, existing plant modifications, and impacts on plant performance. According to the commenters, EPA should have accounted for costs for: (1) Plant modifications listed by EPA as scope adders, (2) initial SCR catalyst, (3) economizer bypass, and (4) proper accounting of annual catalyst costs.

EPA notes that, as described in the Group 2 Boiler Study and in the earlier preamble discussion on the retrofit nature of EPA's control costs, scope adders are items that will not be required for typical NO_X control technology retrofits. Additionally, EPA does not include ''scope adders'' in its estimates of Group 1 LNB costs or in its estimates of Group 2 NO_X control costs. Since the ultimate purpose is to compare Group 1 boiler cost-effectiveness to Group 2 boiler cost-effectiveness, EPA's approach provides for a more consistent cost-effectiveness comparison between the two boiler types. For some special cases, however, scope adders may be required for accommodating the control technology retrofit or may be selected by the owners for other reasons, such as to provide an overall improvement in the plant operations or design. For these reasons EPA's Group 2 Boiler Study presents these costs, though they are not necessary for typical retrofits. The contingency allowances included in all cost estimates in the EPA study will cover any scope adder items that might be required in special cases.

Additionally, EPA's costs include the initial catalyst costs (see docket item IV–A–4, the first item in Table B4–17 and the first direct cost item in Table B4–18) and costs for an economizer bypass (see docket item IV–A–4, the first item of Table B4–17). Further, the approach taken in the EPA study results in a conservative cost estimate for the annual catalyst costs. In the study, it is assumed that one-third of the catalyst would be replaced during each year of operation, starting the very first year, to maintain the performance at the originally specified levels. A less conservative approach would be to assume catalyst replacement starting only in the fourth year of operation, as suggested by the commenter questioning EPA's costs. EPA's approach was taken to simplify the cost estimation as well as to provide more conservative costs.

Several commenters have cited SCR retrofit costs reported by other stakeholders that are higher than EPA's cost estimates. Two of the cost sources reported include DOE and EPRI. Another utility commenter submitted a study conducted recently on its behalf. EPA reviewed the SCR retrofit cost information cited by the above commenters. EPA's evaluation of the information provided by these sources is provided below:

(1) A direct comparison of the DOE model-generated costs was made with the costs in EPA's study. For a 400 MW boiler with the same design basis as that selected for EPA's study boiler (a NO_X reduction efficiency of 50 percent and an inlet NO_X of approximately 770 ppm), DOE reports a capital cost of approximately $50/kW vs. $41/kW reported by EPA. The DOE costs are based on the use of extremely high project and process contingency factors of approximately 25.6 and 15.8 percent, respectively (compared to 15 and 5 percent in EPA's study). In addition, DOE uses a general facility contingency factor of 10 percent (compared to 5 percent in EPA's study). EPA believes that in light of the extensive worldwide experience with SCR retrofits to coal-fired boilers, (see docket item II–I–37, Selective Catalytic Reduction Controls to Abate NO_X Emissions, prepared by the Institute of Clean Air Companies), use of such high contingency factors as in DOE's estimates are unduly conservative. If these differences are eliminated, the capital costs developed by the DOE model would be slightly lower than EPA capital costs: Using the EPA, in lieu of the DOE, contingency factors, DOE's capital costs would be approximately $40/kW, as compared to the EPA cost of $41/kW. Thus, the DOE model supports the results of the EPA study when the effects of overly conservative contingencies are removed. This is verified by calibrating the predictive power of the two models with the only actual retrofit experience. EPA's cost estimates compare more favorably with the only actual retrofit of SCR on a cyclone boiler (Merrimack), predicting a conservative $68.53/kW [21] compared to the actual $56/kW, while DOE's model would predict a significantly higher cost than EPA's estimate.

(2) EPRI quoted a capital cost range for retrofitting SCR to the Group 2 boilers from $70 to $200/kW in its comments and provided no supporting data. These costs are significantly higher than EPA's costs and completely unrealistic when compared to the capital cost of $56/kW reported for the SCR installation at the cyclone boiler at Merrimack Station. This operating installation has been described by the utility that conducted it as a moderately difficult retrofit. Still, even the lower end of the EPRI's cost range is well above the Merrimack-reported cost. The cost range predicted by EPRI is given little weight since the cost range has no supporting data and is inconsistent with the only actual retrofit of SCR on a cyclone boiler.

(3) One of the commenters submitted a report prepared by an independent architectural & engineering firm and containing costs for specific applications of SCR on cyclone boilers. A review of the report revealed the following:

(A) The report itself notes that the nature of the analyses performed was preliminary and states that further detailed evaluation is needed to provide a reliable assessment of the SCR retrofit to the cyclone boilers that were studied. The report relies on constructability evaluations based on a review of drawings only and cost estimates based on a roughly estimated SCR system design. While EPA's study developed detailed component-level costs, the report does not include any details for the cost estimates.

(B) The report discusses the impact of SCR on existing plant equipment. However, the report is not clear as to what type of modifications have been included for what equipment, while EPA's study presents detailed lists of modifications to equipment. The SCR systems have apparently been designed for a NO_X removal efficiency ranging from 35 to 45 percent. The operating costs are based on very low NO_X removal efficiencies ranging from 29 to 38 percent. Both of these assumptions artificially increase the estimated costs/ton of SCR. EPA costs are based on a NO_X removal efficiency of 50 percent (which is easily achievable by SCR).

EPA concludes that the subject report uses questionable assumptions, is not a detailed analysis, provides inadequate supporting details, compares poorly to the only actual retrofit at Merrimack, and thus provides no basis for revising EPA's cost estimates.

In addition to the above sources, some commenters provided SCR cost information based on their own evaluations and studies. In general, these costs are not supported by actual data. In contrast, EPA's study is heavily corroborated by experience and actual data, and therefore, the comments do not provide a basis for revising EPA's cost estimates.

Other commenters have supported the costing methodology used by EPA. Two commenters (one of which has performed the only retrofit of an SCR to a cyclone boiler, i.e., Merrimack Unit 2) provide data from that SCR retrofit in support of the costs developed by EPA.

Response: EPA's costs are intended to cover the SCR retrofit requirements at typical Group 2 cyclone boiler installations. In EPA's evaluation of these costs, it was recognized that the retrofit requirements at some boiler installations could exceed the norm just as other retrofit requirements could be below the norm. Boiler-specific unique requirements beyond the norm were identified as scope-adders in this evaluation. However, the EPA cost estimates included contingency allowances that will cover the cost of these requirements.

As noted in the previous section addressing the retrofit nature of EPA's costs, the Group 2 Boiler Study includes detailed lists of new equipment and existing plant modifications applicable to each technology retrofit. These lists provide detailed information on the hardware associated with typical retrofits and scope adders. Thus, the EPA costs, developed at the hardware component level, include the retrofit requirements for typical and non-typical control technology installations.

The high estimated capital and levelized costs mentioned by some commenters and their sources (e.g., DOE, EPRI, and an architectural/engineering firm hired by one commenter) are not borne out by the reported experience at the aforementioned Merrimack SCR installation. For this 330 MW cyclone-fired installation, designed for a 65 percent NO_X removal efficiency, the total capital cost was reported to be $56/kW. This cost included the addition of a significant amount of additional ductwork and support steel required for this retrofit because of unusual space limitations. The baseline NO_X emission for this unit was also unusually high (2.66 lb/mmBtu), thus requiring a relatively large and expensive ammonia handling system.

[21] This is the capital cost estimate for a boiler of Merrimack's size under EPA's methodology, after adjusting for this particular boiler's NO_X reduction efficiency of 65 percent versus 50 percent used in EPA's study and the boiler's baseline emission level of 2.66 lb/mmBtu versus 1.3 to 1.4 lb/mmBtu used in EPA's study.

EPA used the information available from Merrimack to corroborate its costing methodology (see docket item IV–A–16, SCR model validation study). A comparison of the Merrimack cost with the EPA-reported costs in the Group 2 Boiler Study (August 1995) is not directly possible because of the differences in the design NO_X reduction efficiency (65 percent at Merrimack versus 50 percent in EPA's study) and the baseline NO_X emission levels (2.66 lb/mmBtu at Merrimack versus 1.3 to 1.4 lb/mmBtu in EPA's study). Thus, to ensure proper comparison, EPA included the design criteria used at Merrimack while employing the Agency's costing methodology. The capital cost developed with this approach could then be compared to the actual Merrimack cost for validation purposes.

Table 15 shows an equipment list for the Merrimack installation. This list has been prepared from published information and information received by EPA from the system supplier. It should be noted that this installation did not require some of the existing plant modifications that were included for the boilers used in the EPA study (e.g., replacement of the existing draft fans and an economizer bypass). However, the SCR installation at Merrimack 2 did require extensive flue gas ductwork to accommodate the SCR within the existing setting; further, in this installation, a bypass around the SCR reactor was also provided. The items in Table 15 were accounted for in the EPA cost estimate to model the retrofit at Merrimack Unit 2.

TABLE 15.—MAJOR EQUIPMENT LIST MERRIMACK SCR ANHYDROUS AMMONIA-BASED BOILER SIZE: 330 MW

No.	Item	Description/size
1	SCR reactor	Vertical flow type, 1,615,350 acfm capacity, equipped with a plate type catalyst with 14,124 ft^3 volume placed in two layers, insulated casing with two empty layers for future catalyst addition, sootblowers, hoppers, and hoisting mechanism for catalyst replacement.
3	Anhydrous ammonia storage	Horizontal tank, 250 psig pressure; 87.5-ton storage capacity.
2	Compressors	Rotary type, rated at 400 scfm and 10 psig pressure.
2	Electric vaporizer	Horizontal vessel, 450 kW capacity.
1	Mixing chamber	Carbon steel vessel.
1 Lot	Ammonia injection grid	Stainless steel construction.
1 Lot	Ammonia supply piping	Piping for ammonia unloading and supply, carbon steel pipe: 4.0 in. diameter, 600 ft long, with valves, and fittings.
1 Lot	Air ductwork	Ductwork between air heater, mixing chamber, and ammonia injection grid, carbon steel, 400 ft long, with two isolation butterfly dampers, and expansion joints.
1 Lot	Sootblowing steam piping	Steam supply piping for the reactor sootblowers, consisting of 200 feet of 2″ diameter pipe with an on-off control valve and drain and vent valved connections.
1 Lot	Flue gas ductwork	Ductwork modifications to install the SCR reactors, consisting of insulated duct, isolation damper, turning vanes, and expansion joints.
1 Lot	SCR bypass	Ductwork consisting of insulated duct, 12′x24′ double-louver isolation damper with air seal, and expansion joints.
1 Lot	Ash handling modifications	Extension of the existing fly ash handling system modifications, consisting of one slide gate valves, one material handling valves, one segregating valve, and ash conveyor piping, 180 ft long with couplings.
1 Lot	Controls and instrumentation	Stand-alone microprocessor based controls for the SCR system with feedback from the plant controls for the unit load, NO_X emissions, etc., including NO_X and ammonia analyzers, air and ammonia flow monitoring devices, and other miscellaneous instrumentation.
1 Lot	Electrical supply	Wiring, raceway, and conduit to connect the new equipment and controls to the existing systems.
1 Lot	Foundations	Foundations for the equipment and ductwork/piping, as required.
1 Lot	Structural steel	Steel for access to and support of the SCR reactors and other equipment, ductwork, and piping.

Table 16 shows the capital cost estimate for the Merrimack retrofit using the same cost model that was used to generate costs for EPA's study. As shown in Table 16, the total plant capital requirement according to EPA's model is $68.53/kW, which is over 20% higher than the actual cost reported for Merrimack of $56/kW. Thus, this comparison confirms the conservatism of the cost methodology used in EPA's study.

TABLE 16.—EPA'S RETROFIT CAPITAL COST ESTIMATE SUMMARY FOR SCR MODIFICATIONS TO A CYCLONE-FIRED BOILER

NO_X Control Technology		SCR
Boiler Size (MW)		330
Cost Year		1994
Direct Costs ($/kW):		
SCR reactors/ammonia storage.		31.3
Piping/ductwork		13.1
Electrical/PLC		3.1
Draft fans		0
Platform/insulation/enclosure.		1.1
Total direct costs ($/kW).		48.6
Scope adder costs ($/kW), (Yes/No):.		
Asbestos removal		0
Transformer		0
Air heater modifications.		0
Boiler system structural reinforcement.		0
Total scope adder costs ($/kW).		0
Total direct process capital ($/kW):.		48.6

TABLE 16.—EPA'S RETROFIT CAPITAL COST ESTIMATE SUMMARY FOR SCR MODIFICATIONS TO A CYCLONE-FIRED BOILER—Continued

NO_X Control Technology		SCR
Indirect costs:		
General facilities	5.0%	2.4
Engineering and home office fees.	10.0%	4.9
Process contingency	5.0%	2.4
Project contingency	15.0%	8.7
Total Plant Cost (TPC) ($/kW).		67.1
Construction years		0
Allowance for funds during construction.		0
Total plant investment (TPI) ($/kW).	67.1	
Royalty allowance	0.00%	0
Preproduction cost	2.00%	1.3
Inventory capital	Note	0.13
Initial catalyst and chemicals 0.00%.		0
Total plant requirements ($/kW).		68.53

Note: Cost for anhydrous ammonia stored at site.

Based on the record, including the above comments and responses, EPA concludes that SCR can be applied to cyclone boilers greater than 155 MW with at least 50% NO_X reduction at the cost-effectiveness projected by the Agency and that SCR so applied is comparable to Group 1 LNBs.

iii. Gas Reburning

Several comments were received by EPA concerning the use of gas reburning technology on cyclone boilers. These comments primarily focused on the adequacy of the gas reburning system design and cost estimation procedures used in EPA's evaluation of this technology.

Comment/Analyses: In EPA's evaluation, natural gas was assumed to be available within the plant fence of each application. Some commenters did not agree with this assumption and cited specific examples of plants where the nearest gas supply pipeline is several miles from the plant sites. One commenter quoted a pipeline access cost at $750,000 to $1,000,000 per mile of pipeline. Another commenter provided pipeline costs for a specific station well below that range. Yet another commenter suggested adding a cost of a 10 mile access pipeline in EPA's estimates for this technology. This commenter suggests a minimum cost estimate of $10/kW for this pipeline addition.

Another commenter provided detailed information on the available gas pipeline size, pressure, and distance from the plant for all Group 2 cyclone-fired boilers. This commenter also noted that adequate wellhead supplies exist to provide gas needed for gas reburning and that 77 of the 89 cyclones included in EPA's database are located in the Midwest regions with abundant pipeline capacities.

Another issue raised by some commenters is the natural gas to coal price differential used by EPA in evaluating gas reburning. While one commenter felt that the cost differential used by EPA was low, several commenters either agreed with EPA's cost differential or suggested use of lower differentials. One of these commenters cited the results of a detailed study done to evaluate natural gas/coal price differential at 142 stations, which showed a median differential of only $0.41/mmBtu and a mean average differential of only $0.49/mmBtu. Two commenters suggested using the average differential of $0.96/mmBtu as reported in the EIA's Annual Energy Outlook (1996) for the years 2000 to 2005.

Several commenters were in general agreement with EPA's capital cost estimates for the gas reburning technology. Some provided examples of actual retrofits with costs similar to EPA's costs. Other commenters, however, objected to EPA's cost estimates. One commenter believed that EPA should have included the cost of scope adders in the evaluated technology costs. Some commenters provided their own estimates of the gas reburning cost ($/ton NO_X removed or mills/kWhr) that were higher than EPA's estimates. One of these commenters provided details of a specific study conducted by an architectural engineering firm for specific cyclone boilers. EPA notes that, as described in the earlier preamble discussion on the retrofit nature of EPA's control costs, scope adders are items that will not be required for typical NO_X control technology retrofits. Additionally, EPA does not include "scope adders" in its estimates of Group 1 LNB costs or in its estimates of Group 2 NO_X control costs. Since the ultimate purpose is to compare Group 1 boiler cost-effectiveness to Group 2 boiler cost-effectiveness, EPA's approach provides for a more consistent cost-effectiveness comparison between the two boiler types.

Response: Through the comments received on the proposed rule, additional information has become available on the availability of natural gas supply at the cyclone boiler installations. Based on this new information, EPA has revised its cost estimates for gas reburning to include costs associated with providing access to gas supply beyond the plant fence (see docket item IV-A–4). Further, EPA chose to use the natural gas to coal price differential for the year 2010 since this year would reflect the midpoint of the expected compliance period for most of the Group 2 boilers. According to DOE's Energy Information Administration (EIA) Annual Energy Outlook for 1996, this differential is § 1.10 per mmBtu, expressed in 1990 dollars. The resulting cost-effectiveness of gas reburning, as shown in section III.B.2 of this preamble, meets the cost comparability criteria.

Based on the record, including the above comments and responses, EPA concludes that gas reburning can be applied to cyclone boilers greater than 155 MW with at least 50% NO_X reduction at the cost-effectiveness projected by EPA and that gas reburning so applied is comparable to Group 1 LNBs. As discussed above, applying the requirements of section 407(b)(2), EPA is establishing a NO_X emission limitation for cyclone boilers based on SCR or gas reburning at 50% NO_X reduction performance. The EPA notes that the reliance on gas reburning in setting emission limitations will encourage gas use in appropriate cases.

6. Wet Bottom Boiler NO_X Controls

At the time the proposed rule was issued, EPA believed that combustion NO_X controls (such as overfire air) would be applicable to all wet bottom boilers. This belief was based on an ongoing demonstration by the American Electric Power Company (AEP). Since overfire air (OFA) seemed to be a very cost-effective way of achieving significant reductions (about 50%), EPA did not rely on any other available NO_X control (i.e., SCR or gas reburning) in setting the wet bottom boiler emission limit. EPA has, however, received comments that the AEP demonstration has not been successful and that EPA should investigate the retrofit of SCR and gas reburning to wet bottom boilers.

Comments/Analyses: The utility (AEP) that is conducting the only combustion NO_X control demonstration on a wet bottom boiler has commented that it is inappropriate to use that utility's engineering estimates of what may be achievable using a two-stage OFA system. According to this utility, actual reductions at their wet bottom boiler, based on the retrofit of a two-stage OFA system, have been 22% at 90–100% of full load, 31% at 70% load, and as small as 10% at minimum (60%) load.

One commenter believes that even for boilers to which the two-stage overfire air approach may eventually apply, a technology cannot be considered to be available when a single demonstration had just begun at the time the proposal was signed. The same commenter also expressed concerns related to the fact that the various categories of wet-bottom boilers feature significantly different furnace size and firing characteristics and thus would not be able to achieve acceptable carbon burnout or protection of the lower furnace from corrosion. This commenter also feels that the uncertainty over applicability and control performance prevent a thorough cost evaluation.

According to another commenter, SNCR is estimated to have a cost of over $900/ton removed, while SCR is estimated to have a cost of over $830/ton. Allegedly, these technologies may not be cost-effective when applied to wet bottom boilers.

Other commenters have recommended considering gas reburning and SCR as being viable and cost-effective approaches for controlling NO_X from these boilers.

Response: The AEP demonstration of retrofitting a two-stage OFA system to a wet bottom boiler has not proved to be successful as yet. Thus, EPA does not find this technology to be the best system of continuous emission reduction for wet bottom boilers and is not using the technology to establish a NO_X emission limit for wet bottom boilers in this rulemaking.

In light of the comments received, EPA considered the applicability, likely performance, and projected cost of gas reburning and SCR applications on wet bottom boilers. Using information on full-scale installations of gas reburning and SCR on wet bottom boilers and information received through the comments on the availability of natural gas at the wet bottom boilers, EPA has determined that gas reburning and SCR are available to all wet bottom boilers that will need to reduce NO_X emissions. In any event, EPA maintains that, because they are post-combustion control systems in that they are applied downstream of the main combustion process, both gas reburning and SCR are available to any boiler type, (e.g., in this case wet bottom boilers). 61 FR 1457. Again, because these are post-combustion technologies, their application to wet bottom boilers raises the same applicability and performance considerations as those discussed in the context of cyclone boilers, e.g., in the proposal (61 FR 1468 and 1470). For the same reason, the analysis of issues concerning SCR costs and natural gas availability and costs (e.g., in section III.B.6.ii–iii of this preamble) in the context of applying these technologies to cyclone boilers is fully applicable to the application of these technologies to wet bottom boilers. Having fully addressed gas reburning and SCR applicability, performance, and cost-effectiveness-related issues in the cyclone boiler context, EPA finds that these are the best systems of continuous emission reduction for wet bottom boilers. EPA has estimated the cost-effectiveness of gas reburning and SCR as applied to each boiler in the wet bottom boiler population. The same approach as that used for other boiler types—i.e., of using the boilers' usage and uncontrolled emissions to determined the cost-effectiveness distribution—was used here. The resulting cost-effectiveness for gas reburning and SCR applied to wet bottom boilers, as shown in section III.B.2 of this preamble, meet EPA's cost comparability criteria. Based on the record, including the above comments and responses, EPA concludes that gas reburning and SCR can be applied to wet bottom boilers with at least 50 percent NO_X reduction and that gas reburning and SCR so applied are comparable to Group 1 LNBs. As discussed above, applying the requirements of section 407(b)(2), EPA is establishing a NO_X emission limitation for wet bottom boilers based on gas reburning and SCR at 50 percent NO_X reduction performance.

7. Vertically Fired Boiler NO_X Controls

Comments/Analyses: The Agency received comments from approximately 8 commenters (4 utilities, 1 utility association, 1 environmental association, 1 vendor, and 1 vendor association) on the proposed emission limitation for vertically-fired boilers. The utility commenters generally supported the proposed limitation as being achievable and comparable in cost, but raised some concerns about the ability of the broad variety of boilers in this category to achieve the proposed limit. Two commenters raised specific concerns about the ability of arch-fired boilers to achieve the limit. These commenters noted that because of design differences, neither of the combustion control technologies demonstrated on other vertically-fired boilers could be used on arch-fired boilers.

The environmental association argued that stricter limits should apply. The vendor commenter disagreed with excluding SNCR as a control option based on cost because the only SNCR retrofit on a vertically-fired boiler was installed in an atypical manner with numerous non-licensed design changes.

Response: As discussed in the proposed rule, EPA examined SNCR applications to vertically fired boilers and found that SNCR did not meet the cost comparability requirement. Hence, EPA did not base the proposed emission limit for vertically fired boilers on SNCR. Further, as discussed in the Group 2 boiler support document (see docket item IV–A–4), in its examination of SNCR costs, EPA did not include any atypical design features that could affect costs. Upon review of the record, including the above comments, EPA is not revising its SNCR cost estimates and still maintains that these costs do not meet the cost comparability requirement.

Moreover, EPA, based on its analysis in the proposal and section III.B.2 of this preamble and applying the requirements of section 407(b)(2), concludes that an emission limit should be set for vertically fired boilers based on the application of combustion controls with at least 40% NO_X reduction. However, in light of the information received from commenters showing the unavailability of combustion controls for arch-fired boilers, a subset of the vertically fired boiler category, EPA is excluding these boilers from the emission limitation for vertically fired boilers. Because combustion controls are extremely cost-effective (having a median cost-effectiveness lower than the median for either wall-fired or tangentially fired boilers) and can achieve significant NO_X reduction (at least 40 percent), EPA has determined that combustion controls are the best system of continuous emission reduction for vertically fired boilers and that the emission limit should not be based on other available NO_X control technologies (e.g., gas reburning or SCR) whose cost-effectiveness values would be much higher.

8. Cell Burner Boiler NO_X Control

Comments/Analyses: Utility commenters agreed that plug-in controls for 2-cell burner boilers are available and are comparable to LNBs applied to Group 1 boilers. However, some of these commenters asserted that non-plug-in controls, though available for cell burner boilers, are not comparable to Group 1 LNBs.

A commenter stated that plug-in technology is available for 2-cell burner boilers and comparable to Group 1 LNBs but is unavailable for 3-cell burner boilers. The same commenter stated that non-plug-in technology is an available technology for cell burner boilers. Several utility commenters claimed that non-plug-in technology is not comparable to Group 1 LNBs. One commenter stated that capital costs for non-plug-in retrofits range from $20–27/kW, whereas LNBs average $14/kW. Another commenter estimated non-plug-in retrofit would cost approximately $30/kW as opposed to $6/kW for plug-in retrofit. However, yet another commenter asserted that cost and cost-effectiveness of non-plug-in retrofit at Brayton Point Unit No. 3 are within the cost range for Group 1 LNBs. This commenter used EPA's methodology to determine a cost of $24/kW and cost-effectiveness of $111/ton for the Brayton Point retrofit.

Response: In its proposal, EPA considered plug-in controls to be available for controlling NO_X emissions from 2-cell burner boilers and considered non-plug-in controls to be broadly applicable on cell burner boilers, including those with 3-cell configurations. Further, EPA found both of these controls to be comparable to Group 1 LNBs. The proposed limit of 0.68 lb/mmBtu was then based on achieving 50% NO_X reduction with either of the plug-in or non-plug-in controls.

The comments received support EPA's position with respect to applicability of plug-in and non-plug-in controls and costs of plug-in controls. However, comments express concerns with the costs of non-plug-in controls. EPA continues to believe that non-plug-in controls are comparable to LNBs. EPA's position with respect to cost of non-plug-in controls is supported by the information obtained on the retrofit at Brayton Point Unit 2 by the utility that owns this unit (see docket item IV–D–30). Based on the record, including the above comments and responses, EPA concludes that, as set forth in the proposal and section III.B.2 of this preamble, plug-ins and non-plug-ins applied to cell burner boilers at 50 percent NO_X reduction are comparable in cost-effectiveness to Group 1 LNBs. As discussed above, applying the requirements of section 407(b)(2), EPA is establishing a NO_X emission limitation for cell burner boilers based on plug-ins and non-plug-ins at 50 percent NO_X reduction performance. Because plug-ins and non-plug-ins are extremely cost-effective (having a median cost-effectiveness lower than either wall-fired or tangentially fired boilers) and can achieve significant NO_X reduction (at least 50 percent), EPA has determined that plug-ins and non-plug-ins are the best system of continuous emission reduction for cell burner boilers and that the emission limit should not be based on other available NO_X control technologies (e.g., gas reburning or SCR), whose cost-effectiveness values would be much higher.

9. Revision of Proposed Group 2 Boiler NO_X Emission Limits

In the proposal, EPA chose to set the emission limits for the various Group 2 boiler populations at the emission rates that a target of about 95% of the pertinent populations could meet. In light of the compliance flexibility available due to emissions averaging and AEL, the above approach was considered to be conservative. The Agency, however, requested comment on whether the approach should be consistent with the approach being used in revision of Group 1 boiler limits.[22]

Comments/Analyses: For cell burners, several utility commenters agreed that the proposed emission limit is reasonable. According to one other commenter, experience with cell burner boilers operated by the commenter shows that the proposed limit can be achieved and provides a margin to accommodate uncontrollable variability. However, the commenter believes that any lower limit may be difficult to achieve, especially for boilers owned by other utilities, because the commenter's boilers appear to have below average uncontrolled rates. One other commenter believes that the data from the plug-in retrofit of Muskingum River Unit 5 indicates that the limit can be met. While the design of that unit differs significantly from other cell burner boilers in the AEP system, the commenter supports EPA's proposed limits.

Other commenters support setting more stringent NO_X limits for all Group 2 boilers and cyclones in particular, stating that EPA should set an emission limitation based on the emission rates that 50% of the population can meet, since boilers not meeting the resulting limitation can average their emissions with other, lower emitting boilers, or apply for an AEL.

Response: EPA based the emission limit for Group 2 boilers on the emission rate that 85 percent to 90 percent of the affected boilers could meet on an individual unit basis. Based on the comments, EPA concludes that it should be consistent in its approaches for establishing the emission limits for Phase II, Group 1 boilers and Group 2 boilers. In light of the compliance flexibility available due to emissions averaging and alternative emission limitations (AELs), this approach is reasonable. Since there is no restriction on what boiler types may be included in an averaging plan, Phase II, Group 1 and Group 2 boilers have the same overall opportunities for averaging. Under the NO_X regulations, the availability of AELs is also not different among boiler types.

As explained in the context of Group 1 boilers, in its Group 2 boiler database, EPA replaced long term ETS uncontrolled NO_X rates with short term CREV rates (see docket item IV–A–4). Using short-term CREV data and quality assured short-term emission data, EPA was able to obtain uncontrolled emission data for about 98% of the Group 2 population. This revised database was used in establishing any revised emission limits described below.

i. Cell Burners

As elaborated above, none of the commenters, including utilities with cell-burner NO_X control retrofits claimed that the proposed 0.68 lb/mmBtu was not a reasonable limit to require if plug-ins or non-plug-ins were installed. The only adverse comments were either that the control technology (i.e., non-plug-ins) is not comparable to LNBs on Group 1 boilers or that a more stringent emission limit should be established. EPA's projections show that about 80 percent of the cell burner boilers can achieve the 0.68 lb/mmBtu limit on an individual unit basis. Although EPA's general approach is to set the emission rate at a level that 85 percent to 90 percent of the units are projected to achieve on an individual unit basis, EPA decided, in these unique circumstances where no commenter contests the achievability of 0.68 lb/mmBtu with plug-ins or non-plug-ins, to set that level as the emission limit. With commenters asserting that a more stringent rate may not be achievable, there is no basis for setting a lower limit. For this reason and the reasons set forth in section I.B.1 of this preamble, EPA is setting 0.68 lb/mmBtu as the emission limit for cell burners based on plug-ins and non-plug-ins.

ii. Cyclones

As explained above, EPA is establishing an emission limit for cyclone boilers greater than 155 MW based on gas reburning and SCR at 50% NO_X reduction performance. Applying the projected 50% emission reduction to the uncontrolled emissions of each boiler in the cyclone boiler population for which NO_X limits are to be set under section 407(b)(2), EPA determined the percentage of the boilers that could achieve various NO_X performance levels

[22] For the Group 1 emission limits, EPA based the achievable limit on the point at which approximately 90% of the affected boilers would likely meet the limit.

on an individual unit basis, as shown in the table below.

NO_X level (lb/mmBtu)	% of boilers meeting NO_X level
1.12	100
0.92	95
0.88	90.9
0.86	89
0.82	86

The table indicates that 89% of the cyclone boilers can achieve on an individual unit basis a NO_X controlled emission rate of 0.86 lb/mmBtu. Applying its general approach of setting emission limits based on reasonable achievability, EPA sets that rate as the emission limit based on gas reburning and SCR. EPA recognizes that a rate of 0.87 lb/mmBtu would also yield an 89 percent individual-unit achievability level. However, because of emissions averaging under § 76.10, this would likely reduce the amount of NO_X reductions realized since a cyclone boiler could meet 0.86 lb/mmBtu and other units in an averaging plan could use the excess reduction to reduce less themselves. Taking account of this likely environmental result, EPA adopts the 0.86 lb/mmBtu emission limit.

iii. Wet Bottom Boilers

As explained above, EPA is establishing an emission limit for wet bottom boilers greater than 65 MW based on gas reburning and SCR at 50% NO_X reduction performance. Applying the projected 50% emission reduction to the uncontrolled emissions of each boiler in the wet bottom boiler population for which NO_X limits are to be set under section 407(b)(2), EPA determined the percentage of the boilers that could achieve various NO_X performance levels on an individual unit basis, as shown in the table below.

NO_X level (lb/mmBtu)	% of boilers meeting NO_X level
0.95	100
0.94	91
0.84	87.8
0.8	78.7

The table indicates that 87.8% of the wet bottom boilers can achieve a NO_X controlled emission rate of 0.84 lb/mmBtu. Applying its general approach of setting emission limits based on reasonable achievability, EPA sets that rate as the emission limit based on gas reburning and SCR. EPA recognizes that a rate of up to 0.93 lb/mmBtu would also yield an 87.8 percent individual-unit achievability level. However, because of emissions averaging under § 76.10, this would likely reduce the amount of NO_X reductions realized since a wet bottom boiler could meet 0.84 lb/mmBtu and other units in an averaging plan could use the excess reduction to reduce less themselves. Taking account of this likely environmental result, EPA adopts the 0.84 lb/mmBtu emission limit.

iv. Vertically Fired Boilers

As explained above, EPA is establishing an emission limit for vertically fired boilers, excluding arch fired boilers, based on combustion controls at 50% NO_X reduction performance. Applying the projected 50% emission reduction to the uncontrolled emissions of each boiler in the vertically fired boiler population for which NO_X limits are to be set under section 407(b)(2), EPA determined the percentage of the boilers that could achieve various NO_X performance levels on an individual unit basis, as shown in the table below.

NO_X level (lb/mmBtu)	% of boilers meeting NO_X level
1.00	100
0.85	96.4
0.83	92.9
0.80	89.3
0.74	82.1

The table indicates that 89.3% of the vertically fired boilers can achieve a NO_X controlled emission rate of 0.80 lb/mmBtu. Applying its general approach of setting emission limits based on reasonable achievability, EPA sets that rate as the emission limit based on combustion controls. EPA recognizes that a rate of up to 0.82 lb/mmBtu would also yield an 89.3 percent individual-unit achievability level. However, because of emissions averaging under § 76.10, this would likely reduce the amount of NO_X reductions realized since a vertically fired boiler could meet 0.80 lb/mmBtu and other units in an averaging plan could use the excess reduction to reduce less themselves. Taking account of this likely environmental result, EPA adopts the 0.80 lb/mmBtu emission limit.

C. Compliance Issues

This final rule implements Phase II of the Nitrogen Oxides Reduction Program for which EPA must: (1) Determine if more effective low NO_X burner technology is available to support more stringent standards for Phase II, Group 1 boilers than those established for Phase I; and (2) establish limitations for Group 2 boilers based on NO_X control technologies that are comparable in cost-effectiveness to LNBs.

A utility can choose to comply with the rule in one of three ways: (1) Meet the standard annual emission limitations at each of its units; (2) average the emission rates of two or more units that it owns or operates, which allows utilities to over-control at units where it is technically easier and less expensive to control emissions and under-control at other units; or (3) if the standard emission limit cannot be met at a unit after installing the technology on which the limit is based and which is designed to meet the limit, the utility can apply for a less stringent alternative emission limit (AEL). Phase I units are required to meet the applicable limits by January 1, 1996; under the proposed rule, EPA stated that the statutorily mandated date by which Phase II units must meet the applicable limits is January 1, 2000.

Comment: Utility commenters contend that the language in section 407(b)(2) shows that there is no statutorily required compliance date for Phase II, Group 1 and Group 2 boilers. EPA allegedly has no basis to set any deadline until it provides appropriate justification. They contend that EPA must provide a statement of purpose justifying the reasonableness of the January 1, 2000 deadline or propose an alternative that can be justified. Commenters also express concern that scheduling the design, procurement, and testing of NO_X retrofit technologies will make compliance with the January 1, 2000 deadline difficult, especially since four times as many boilers are subject to NO_X emission limitations in Phase II as were in Phase I. Other commenters contend that EPA does not have the authority to extend the compliance date because, except in cases where the Act requires earlier compliance, it clearly requires compliance by January 1, 2000. Other commenters state general opposition to extending the compliance deadline because of industry awareness of impending emission reductions that would be required and because any delay in the implementation of the rule will only serve to delay the benefits associated with the rule. Many commenters opposed to an extension in the compliance date state that the availability of compliance alternatives (i.e., averaging and AELs) support the establishment of limits more stringent than those proposed.

Response: Some commenters argue that section 407 does not set a specific deadline for compliance by Phase II, Group 1 and Group 2 boilers with Phase II NO_X emission limitations. According to these commenters, by not setting a specific Phase II deadline, section 407 left the matter to the discretion of the Administrator.

EPA concludes, however, that section 407 sets a Phase II compliance deadline of January 1, 2000 both for Group 1 boilers subject to the Phase II NO_X emission limitations under section 407(b)(2) and Group 2 boilers. Section 407(a), entitled ''Applicability'', states:

> *On the date that a coal-fired utility unit becomes an affected unit pursuant to section 404, 405, 409,* or on the date a unit subject to the provisions of section 404(d) or 409(b), must meet the SO_2 reduction requirements, *each such unit* shall become an affected unit for purposes of this section and *shall be subject to the emission limitation for nitrogen oxides* set forth herein. 42 U.S.C. 7651f(a), (emphasis added).

The provision first establishes a general rule that a coal-fired unit becomes ''subject to'' the applicable NO_X emission limitation on the date that the unit becomes an ''affected unit under sections 404, 405, (or) 409'' (42 U.S.C. 7651f(b)(1)), i.e., on the same date it becomes subject to the SO_2 emissions limitation. The Act defines ''affected unit'' as a unit that is ''subject to the emission reduction requirements or limitations under (title IV)''. 42 U.S.C. 7651a(2). Sections 404 (covering Phase I units in Phase I), 405 (covering Phase I and Phase II units in Phase II), and 409 (covering Phase II repowering extension units) are the sections under which utility units are allocated SO_2 allowances under Phase I and Phase II,[23] which allowances serve as the SO_2 emissions limitation unless the unit buys or sells allowances. EPA concludes that the phrase, ''affected unit under section 404, 405, [or] 409'', refers to a unit that is subject to the SO_2 emissions limitation established in those sections.

EPA maintains that the general rule established in section 407(a) governs and, when applied to specific units, sets a specific NO_X compliance deadline, except to the extent any other provision in section 407 modifies that compliance deadline. There are additional provisions, including a portion of section 407(a) itself, that address the compliance deadline. However, contrary to some commenters, the existence of those provisions does not mean that section 407(a) fails to set a general rule for determining the compliance deadline. On the contrary, these additional provisions modify the general rule for the NO_X compliance deadline but only for specified categories of units.

In particular, section 407(a) itself contains an exception for those units (i.e., Phase I extension units under section 404(d) and Phase II repowering extension units under section 409(b)) that are given extra allowances to extend the date by which they are required to make reductions in SO_2 emissions. The provision similarly extends the deadline for NO_X compliance to coincide with the year in which the extra allowance allocations cease. This provision modifies, for those categories of units, the general rule for the NO_X compliance deadline.

In addition, section 407(b)(1), which requires the Administrator to set NO_X emission limitations for tangentially fired and dry bottom wall fired boilers, states:

> *After January 1, 1995, it shall be unlawful for any unit that is an affected unit on that date* and is of the type listed in this paragraph to emit nitrogen oxides in excess of the emission rate set by the Administrator pursuant to (section 407(b)(1)). 42 U.S.C. 7651f(b)(1) (emphasis added).

This provision modifies the general rule for NO_X compliance deadlines, as applied to Phase I units. Under section 407(a), Phase I units would be subject to the applicable Phase I NO_X emission limitation on the date that they become subject to the Phase I SO_2 emission limitation. However, the section 407(b)(1) provision limits the application of such a NO_X compliance deadline to those Phase I units that, as of January 1, 1995, are subject to the SO_2 emissions limitation. All Table A units are subject to the SO_2 limitation on January 1, 1995, but only substitution units with substitution plans approved and effective as of that date meet that requirement. EPA has interpreted this provision to mean that substitution units with plans approved and effective after January 1, 1995 are not subject to the NO_X emission limitations until January 1, 2000, the date on which they are subject to the SO_2 emission limitation under section 405. 40 CFR 76.1(c). In short, contrary to some commenters, section 407(a) does not make the section 407(b)(1) provision redundant; the section 407(b)(1) provision modifies, for some Phase I units, the general rule established in section 407(a) for determining NO_X compliance deadlines.

In addition, section 407(d) provides for a 15-month extension of the compliance date for Phase I units that are subject to section 407(b)(1) and meet certain requirements. The extension is provided for units whose owner or operator shows that the necessary control technology is not ''in adequate supply to enable its installation and operation at the unit, consistent with system reliability, by January 1, 1995''. 42 U.S.C. 7651f(d).

Despite these modifications of the general compliance deadline provision in section 407(a), that general provision still governs certain categories of units. For example, section 407(b)(2) provides that the Administrator may revise by January 1, 1997 the NO_X emission limitations, set under section 407(b)(1) for tangentially fired and dry bottom wall fired boilers. Under section 407(a), any revised emission limitations apply to units starting on the date on which they become subject to the SO_2 emissions limitation, i.e., January 1, 2000 for Phase II units that are allocated allowances under section 405 and have tangentially fired or dry bottom wall fired boilers. In order to remove any ambiguity as to whether revised emission limitations would apply to Phase I units subject to the original limitations for tangentially fired or dry bottom wall fired units, there is a proviso at the end of section 407(b)(2) stating that such Phase I units are not subject to any revised emission limitation.

Similarly, the general compliance deadline provision applies to Phase II units that are allocated allowances under section 405 and have other types of coal-fired boilers. Under section 407(a), those units are subject to the NO_X emission limitations for their respective boiler types starting on the date on which they are subject to the SO_2 emissions limitation, i.e., January 1, 2000.

Some commenters suggested that section 407(a) merely establishes what units are affected units subject to NO_X emission limits and not the date on which the NO_X emission limits apply. However, it is difficult to see how a section that identifies ''the date'' on which a unit is ''subject to'' the NO_X emission limits could be interpreted as not setting a NO_X compliance deadline. These commenters attempted to circumvent this language in section 407(a) by distinguishing between (1) the date on which a unit is ''an affected unit under section 407'' and is ''subject to'' the NO_X emission limits and (2) the date on which a unit must comply with such emission limits. Allegedly, a unit can be ''subject to'' an emission limit on a given date but not required to comply with such emission limit until a later date.

The commenters' interpretation of section 407(a) renders meaningless the establishment of a specific date on which a unit becomes ''subject to'' the

[23] Section 406, which provides for bonus allowances if elected by a State Governor, changes the bonus allowances for 2000–2009 under section 405 for units located in the State.

NO_X emission limit. If a unit is ''subject to'' a NO_X emission limit on a given date without being required to meet the limit on that date, then the specific date on which the unit becomes ''subject to'' the limit is of no consequence. Other sections of title IV impose the non-emission-limit requirements concerning NO_X (e.g., the requirement to submit a permit application and compliance plan under section 408(f) and the monitoring requirements of section 412) on affected units but specify different dates by which those requirements must be met. The subject-to-the-limit date under section 407(a) is irrelevant to the non-emission-limit requirements; in fact, the compliance dates for the non-emission-limit requirements logically precede the subject-to-the-limit dates under section 407(a). *See, e.g.,* 42 U.S.C. 7651g(c)(1)(A) (deadline for submission of Phase I NO_X compliance plans) and (f) (deadline for submission of Phase II NO_X compliance plans) and 42 U.S.C. 7651k(b) (deadline for submission of Phase I unit monitor installation) and (c) (deadline for Phase II monitor installation). Yet, Congress carefully crafted language in section 407(a) to identify specific dates on which units become ''subject to'' the NO_X emission limits. Because the commenters' interpretation essentially reads this carefully crafted language out of the statute, EPA rejects this interpretation.[24]

In support of their interpretation, the commenters pointed to language in section 405 with regard to SO_2 emissions limitations. While the first sentence of section 405(a) states that each existing unit is ''subject to'' the limitations in the section ''(a)fter January 1, 2000'' (42 U.S.C. 7651d(a)(i)), subsequent provisions of section 405 state that ''after January 1, 2000, it shall be unlawful for'' a given category of units to exceed the applicable SO_2 emissions limitation. *See, e.g.,* 42 U.S.C. 7651d(b)(1). However, despite some similarity in language in sections 405 and 407, the commenters ignore a crucial difference between the sections. On its face, the first sentence of section 405(a)(i), which establishes the January 1, 2000 compliance date for all existing utility units, is a short-hand summary of the long series of subsequent provisions of section 405. Those provisions (section 405(b) through (j)) repeat the January 1, 2000 compliance date[25] and then lay out in detail the formulas for allocating allowances for specific categories of existing utility units. In contrast, as discussed above, section 407(a) sets the general rule for determining a unit's compliance date for the NO_X emission limitations, and the subsequent provisions in section 407(a) and other parts of section 407 modify that compliance date for some, but not all, categories of units.[26]

Regarding concerns expressed by some commenters about retrofitting NO_X control systems to meet the January 1, 2000 compliance deadline, actual experience to date in preparing for Phase I indicates the commenters' anticipated technology shortage may not materialize. Out of 266 Phase I boilers subject to Phase I NO_X emission limitations, EPA received only 9 requests for the 15-month compliance extension under section 407(b)(2) of the Act. Moreover, EPA has already received numerous inquiries and submissions concerning the early election provision in § 76.8 of the NO_X rule, which allows for compliance with the Phase I NO_X emission limitations in 1997 by units subject to NO_X emission limitations starting in Phase II. This suggests that an adequate supply of NO_X control technologies is available.

In any event, Congress, in section 407(a), set a fixed NO_X compliance date for units subject to the revised emission limits under section 407(b)(2) of the Group 1 emission limits. Further, while Congress was obviously aware of the option—which it exercised with regard to Phase I—of providing for 15-month extensions of the statutory compliance deadline for Phase II, Congress did not adopt such a provision. EPA concludes that it therefore lacks the statutory authority to establish such an extension by regulation.

D. Title IV NO_X Program's Relationship to Title I and NO_X Trading Issues

The provisions of title IV, which specify requirements for NO_X reductions in order to control acid deposition, have often been compared to provisions of title I, which specify requirements for attainment and maintenance of national ambient air quality standards. Since NO_X reduction is an integral element in achieving the air quality goals as specified under both titles, general concern has been expressed as to the consistency, compatibility, and necessity of potentially duplicative regulatory burdens for those utilities subject to regulations under both titles.

Further, in the preamble to the proposed rulemaking, EPA solicited comment on the legal basis and workability of a NO_X trading system under title IV. *See* 61 FR 1477. NO_X trading involves giving credit for emission reductions that are achieved beyond the minimum required by applicable emission limitations and allowing credits to be transferred for use by other entities in meeting their emission limitations. In the proposal preamble, EPA noted that regional emissions trading is being considered by the eastern U.S. to address ozone nonattainment problems in that region. The preamble discussed the efforts of the Ozone Transport Commission (OTC) to develop a NO_X cap and trade program, which is similar to the Acid Rain SO_2 cap and trade program, for the northeast and of the Ozone Transport Assessment Group (OTAG) to consider a corresponding NO_X program for the eastern half of the U.S. EPA's guidance on open market trading was also discussed.

Comment: Utilities commented on the legal necessity to coordinate compliance deadlines of title IV with other NO_X initiatives, referencing the requirements of Executive Order 12866. The same commenters encouraged the Agency to tailor its regulations to impose the least burden on society. Other utility commenters recommended that EPA establish compliance deadlines by accounting for other regulatory initiatives. Some commenters favored a title IV NO_X compliance extension option for those boilers also obligated to meet more stringent title I requirements.

A number of commenters favored the implementation of a NO_X trading program, agreeing that such a program would result in increased flexibility and allow NO_X reduction strategies at least

[24] While the compliance-date provisions of section 407 are not well written and are difficult to parse, EPA does not conclude that the provisions are ambiguous. However, if they were considered ambiguous, the Agency maintains that its interpretation is reasonable.

[25] The repetition of only the January 1, 2000 date in this context is not a basis for rejecting this interpretation of section 405.

[26] The commenters also cite language in sections 404 and 412. The first sentence of section 404(a)(1) states that ''(a)fter January 1, 1995, each source that includes one or more units listed in Table A is an affected source under this section'', and the second sentence adds that ''(a)fter January 1, 1995, it shall be unlawful for any affected unit'' to exceed the SO^2 emissions limitation. 42 U.S.C. 7651c(a)(1). EPA's approach to interpreting section 407(a) does not render superfluous the second sentence of section 404(a)(1). The first sentence addresses only Table A units and explains that a source that includes any such unit is an affected source. The second sentence addresses all affected units in Phase I, which includes substitution units under section 404(b) and (c) and compensating units under section 408(c)(1)(b), and sets forth in detail their SO2 emissions limitation. Similarly, the cited language in section 412(e) (i.e., ''(i)t shall be unlawful'' tooperate without complying with section 412) is irrelevant to the interpretation of section 407. The section 412 language does not relate at all to emission limitations and refers, in general terms, to the requirements specified in the other provisions of section 412.

cost. At issue is the legality of implementing such a program under title IV, the possibility for increased emissions as a result of such a program, and the administrative actions necessary to develop and implement a successful program. Most commenters recommended a cap and trade program instead of an ''open market'' trading program.

Response: EPA believes that the NO_X reduction requirements under titles I and IV are not fundamentally inconsistent. As discussed in section I.B.2 of this preamble, each of the goals of achieving ozone attainment, reducing acid deposition, and reducing eutrofication will likely require significant, additional regional reductions in NO_X. The level of needed reductions will likely be much greater than those achievable under the title IV NO_X emission limitations established under today's final rule. Further, there is no record evidence that the NO_X control technologies on which the title IV NO_X emission limitations are based are incompatible with more advanced technologies that may be needed to comply with title I. On the contrary, to the extent title I requires the addition of post-combustion controls on units with combustion controls under title IV or requires more intensive use of post-combustion controls installed under title IV, the requirements of the titles are compatible.

However, EPA believes that NO_X reduction initiatives under title I and title IV should be coordinated, consistent with statutory requirements, in a way that promotes the goal of achieving necessary NO_X reductions in a cost effective manner. In particular, today's final rule promotes this goal by including provisions that address the interaction of efforts under title I to reduce NO_X emissions through cap and trade programs and the establishment of above-discussed title IV NO_X emission limits for Phase II.

With regard to title I, EPA actively supports, with the Department of Energy, OTAG's efforts to develop a consensus approach for regulation of NO_X emissions in the eastern half of the country in order to achieve ozone attainment throughout that region. Achievement of ozone attainment is likely to require additional NO_X emission reductions significantly exceeding the reductions called for under today's final rule. EPA supports OTAG's goal of reaching consensus among the States on an approach and having the States voluntarily implement the approach. However, EPA has indicated that if the States fail to implement through State Implementation Plans an OTAG-developed approach for accomplishing ozone attainment throughout the region, EPA will take action to ensure that State Implementation Plans or Federal Implementation Plans are put in place to address ozone attainment.

Among the approaches under consideration by OTAG is a region-wide cap and trade program for NO_X emissions. As has been demonstrated by the Acid Rain Program with regard to SO_2 emissions, a cap on total annual NO_X emissions for the region will assure achievement of the necessary overall NO_X emission reductions while trading of NO_X emission authorizations or allowances will enable sources to reduce the costs of making reductions. EPA therefore believes that a region-wide cap and trade program is the best method for achieving necessary NO_X reductions.

Utility boilers subject to the NO_X emission limitations established by today's final rule are likely to face significant, additional NO_X reduction requirements (e.g., under an OTAG-developed approach to achieve regional ozone attainment). If, as EPA supports, the ozone attainment requirements are implemented in the form of a cap and trade program and the program results in utility NO_X emission reductions exceeding those that would be required by utilities complying with today's final rule, EPA maintains that the cap and trade system should be relied on, in lieu of this rule, to the fullest extent permissible under the Clean Air Act. Under such an approach, the reductions achievable under the rule will still be realized but in a manner that allows utilities to take advantage of the cost savings that result from flexibility within a cap to trade allowances among utilities, as well as among boilers owned by a single utility. Relief from the emission limits set by the rule is appropriately limited to utility boilers in the State or States covered by the cap and trade regime.

Under § 76.16 of the final rule, the Administrator retains the authority to relieve boilers subject to a cap and trade program under title I from the emission limitations established in today's final rule under section 407(b)(2) if the Administrator finds that alternative compliance through the cap and trade program will achieve more overall NO_X reductions from those boilers than will the section 407(b)(2) emission limitations. Section 76.16 sets forth the criteria that the cap and trade program must meet in order to ensure that the program will yield the necessary NO_X reductions. Since alternative compliance will be allowed only if the necessary NO_X reductions will still be made, this approach is consistent with the purposes of title IV and the Clean Air Act in general.

EPA maintains that it has the authority under section 407(b)(2) to provide relief from the revised Group 1 limits and the Group 2 limits where the cap and trade program, replacing those limits, provides for greater NO_X emission reductions and thus greater environmental protection. With regard to Group 1 boilers not subject to the existing Group 1 limits until 2000, section 407(b)(2) provides that the Administrator ''may'' establish more stringent emission limitations if more effective low NO_X burner technology is available. 42 U.S.C. 7651f(b)(2). As discussed above, the Administrator is exercising her discretion to revise the Group 1 limits because more effective low NO_X burner technology is available and the resulting additional reductions are cost-effective, represent a reasonable step toward achieving significant, regional NO_X reductions that are likely to be needed, and are consistent with section 401(b). If it is determined that, for boilers in certain States, NO_X emissions will be lower under a cap and trade program than under the revised Group 1 limits (and the Group 2 limits), it is reasonable to conclude that, for those boilers, it is not necessary to revise the Group 1 limits.

Imposing the revised Group 1 limits on boilers subject to such a cap and trade program could limit the flexibility of utilities under the cap and trade program and thereby limit the potential cost savings from trading. While emissions averaging under section 407(e) provides some flexibility for a utility to overcontrol at its cheaper-to-control boilers and undercontrol at its expensive-to-control boilers, averaging is limited by statute to boilers with the same owner or operator. In contrast, under a cap and trade program, utilities may overcontrol at some of their units and sell NO_X allowances to other utilities that may undercontrol at some of their units. It is this greater flexibility, within a total annual emissions cap, that provides the opportunity to reduce compliance costs. If boilers subject to a cap and trade program are relieved of compliance with the revised Group 1 limits, this will likely result in achievement of reductions in a more cost effective manner than if the revised Group 1 limits continued to be imposed on these boilers.

Section 407(b)(2) gives the Administrator discretion to make the existing Group 1 limits more stringent, but not to relax the existing limits. Thus, the existing Group 1 limits, established by the April 13, 1995 regulations, will apply to Group 1 boilers covered by a cap and trade program. While retaining the existing Group 1 limits means that there may be less flexibility than if there were no section 407 limits on these boilers, relieving the boilers of the revised Group 1 limits still results in some increased flexibility and therefore is likely to yield cost savings.

Similarly, with regard to Group 2 boilers, section 407(b)(2) requires that the Administrator, taking account of environmental and energy impacts, set emission limits that are based on the reductions achievable using available control technologies with cost effectiveness comparable to LNBs on Group 1 boilers. In setting the Group 2 limits, the Administrator relied in part on the additional NO_X reductions that will result and determined that these reductions are cost-effective, are a reasonable step toward achieving necessary regional NO_X reductions, and are consistent with section 401(b). Again, if greater reductions from boilers in a State or group of States can be achieved through a cap and trade program in a more cost effective manner than through imposition of Group 2 limits (and revised Group 1 limits) on the boilers, it is reasonable to relieve those units of the Group 2 limits. Taking account of these environmental and cost impacts, the Administrator can, in such circumstances, allow the cap and trade program to apply in lieu of the Group 2 limits.

Section 76.16 of the final rule establishes the procedural and substantive requirements for relieving boilers of the revised Group 1 limits and the Group 2 limits. The rule itself does not grant or require such relief. Under this section, the Administrator has the discretion to act, on a case-by-case basis consistent with the established procedures, to provide such relief if he or she determines that the substantive requirements are met. As noted above, EPA supports the cap and trade approach for achieving necessary reductions of regional NO_X emissions.

Consideration of whether to relieve boilers under a cap and trade program of the section 407(b)(2) limits may be initiated either by a petition by a State or group of States or on the Administrator's own motion. Because of the large number of utility companies and coal-fired boilers and the complexities that would result if relief from the section 407(b)(2) limits were considered on a boiler-by-boiler or utility-by-utility basis, the rule requires that any request for, and any determination whether to grant, such relief be made for an entire State or entire group of States. The cap and trade program involved must therefore cover, for an entire State or group of States, all the units for which relief is sought or considered. This approach has the added benefit of making it more likely that the cap and trade program involved will be broad enough to provide a robust NO_X allowance market.

Further, the cap and trade program may be established through State Implementation Plans or Federal Implementation Plans covering the States involved. The relief from section 407(b)(2) limits is potentially available whether the cap and trade program is adopted voluntarily by the OTAG States or imposed by EPA under title I. State petitions for such relief may be submitted, and the Administrator's consideration of whether to grant relief may commence, before the State Implementation Plans or Federal Implementation Plans or revised Plans establishing the cap and trade program are final and federally enforceable. This allows the process of deciding whether to grant relief from the section 407(b)(2) limits to be coordinated with the processing of these Plans. However, relief may not be granted until the Plans establishing the cap and trade program are actually in place, i.e., are final and federally enforceable.

The substantive requirements that must be met by the cap and trade program are essentially the same whether the program is implemented through a State Implementation Plan or a Federal Implementation Plan and whether the consideration of relief from section 407(b)(2) limits is initiated by petition or on the Administrator's own motion. The Administrator has discretion to grant relief only if the cap and trade program meets certain requirements aimed at ensuring that the necessary NO_X reductions will still be achieved and that the program creates an opportunity for cost savings. First, each unit that is in the State or group of States and that would otherwise be subject to title IV NO_X emission limits must be subject to a cap on total annual NO_X emissions or two or more seasonal caps that together limit total annual NO_X emissions. This allows for a cap and trade program with different caps during different seasons, e.g. a summer cap aimed primarily at ozone attainment and a cap for the rest of the year.

Second, the units must be allowed to trade authorizations to emit NO_X within the cap. This element is what provides utilities the flexibility to reduce the costs of making the reductions necessary for achievement of the cap.

Third, the units must surrender authorizations to emit NO_X (i.e., NO_X allowances) to account for their NO_X emissions during the period covered by the cap. In addition, the units must be required to surrender allowances to account for the NO_X emission consequences of reducing utilization at the generation facilities covered by the cap and shifting utilization to generation facilities not covered by the cap. This addresses a problem that potentially arises whenever a cap and trade program covers some but not all generation facilities. If a utility can reduce the use of a unit covered by the cap and offset the resulting reduced generation with generation at a unit not covered by the cap, circumvention of the cap may result. Because of the offsetting utilization changes at the two units, the atmosphere may receive the same total amount of NO_X emissions from the units. In addition, if allowances are used only to account for emissions by the unit subject to the cap, the unused allowances are available for use by other units subject to the cap. The net result is that the total emissions in the atmosphere (including emissions by the reduced-utilization unit, the increased-utilization unit, and the units acquiring and using the unused allowances) may exceed the cap. This is analogous to the reduced utilization problem in the SO_2 cap and trade program in Phase I, during which most units in the U.S. are not covered by the requirement to hold allowances for their SO_2 emissions. *See* 58 FR 60950, 60951 (November 18, 1993). Section 408(c)(1)(B) of the Act and §§ 72.91 and 72.92 of the regulations require SO_2 allowance surrender to account for the emissions consequences of reduced utilization. *See* 60 FR 18462–63 (April 11, 1995).

The NO_X cap and trade program must include appropriate allowance surrender provisions to address this problem by requiring NO_X allowance surrender to the extent necessary to account for the increased NO_X emissions, if any, at generation facilities (i.e., combustion devices serving generators that produce electricity for sale) not covered by the cap. EPA recognizes that any allowance surrender provisions can only approximate the emissions consequences of shifting utilization from within-the-cap facilities to outside-the-cap facilities. *See* 60 FR 18466. EPA will evaluate NO_X allowance surrender provisions in light of this limitation and of the importance of adopting provisions that are workable and not overly complicated. Moreover, EPA believes that effective NO_X

allowance surrender provisions can be developed that are less complex than those in place for reduced utilization in the SO_2 allowance trading program. EPA also notes that the larger the group of States covered by the cap and the more comprehensive the coverage by the cap of generation facilities in such States, the smaller the potential for shifting utilization from units under the cap to units outside the cap. For example, the problem of shifting utilization, and therefore the associated allowance surrender, will be significantly smaller for a cap and trade program covering the generation facilities in the entire 37–State OTAG area.

Fourth, the total annual emissions by all units that are subject to the cap and that would otherwise be subject to the section 407(b) limits must be less than the total annual emissions of such units if they were subject to the section 407(b) limits (without adjusting for alternative emission limitations and averaging). In determining the units' total annual emissions under the section 407(b) limits, the effect of alternative emission limitations—which reduce the amount of NO_X reductions achieved and whose precise levels for individual units would be difficult if not impossible to project—will not be considered. Requiring the cap and trade program to yield fewer total annual emissions than the section 407(b) limits without considering alternative emission limitations will help ensure that the environmental benefits of the section 407(b)(2) are preserved under the cap and trade program. *See* Economic Incentive Program Rules, 59 FR 16690, 16694 (April 7, 1994).

In addition, the effect of averaging will not be considered because of the following reasons. If averaging is limited to units that are also subject to the cap and trade program, averaging is unnecessary to separately consider because it would not affect the total emissions of the averaging units under the section 407(b) limits. *See* 60 FR 18756 (explaining that average emission rate of units in averaging plan cannot exceed average emission rate if they had operated in compliance with §§ 76.5, 76.6, or 76.7 limits). If averaging includes units not subject to the cap and trade program and those units select emission rates under the plan that exceed the standard limits, this could have the effect of understating the reductions achieved under the title IV limits.

In order to avoid disputes over what year to use in comparing total annual emissions under the cap and trade program and the section 407(b) limits, the rule specifies how to select the year. The approach in the rule ensures that actual data is available for such year.

In addition to the substantive requirements for relieving units of the section 407(b)(2) limits, the rule addresses the procedures that the Administrator must follow in determining whether to exercise his or her discretion to grant relief. The Administrator must make this determination in a draft decision, subject to notice and comment, and then in a final decision. The draft decision must set forth not only the determination and its basis but also the specific procedures that will govern the issuance and any appeal of the final decision. The rule imposes certain minimum procedural provisions that must be set forth in the draft decision These procedural requirements are closely modeled after the procedures in part 72 of the Acid Rain regulations for the issuance of Acid Rain permits.

Notice of the draft decision must be provided by service on interested persons and on the air pollution control agencies in States that may be affected by the draft decision. This includes not only the States in which the units involved are located, but also neighboring States. The description in the rule of the neighboring States (and neighboring, federally recognized Indian Tribes) on which notice must be served is based on the definition of ''affected States'' in the recently issued part 71 regulations, which govern federal issuance of title V operating permits. *See* 61 FR 34202, 34229 (July 1, 1996). Notice must also be provided in the Federal Register and equivalent State publications. Notice in newspapers in general circulation in the areas in which the units involved are located is not required. EPA maintains that newspaper notice in these circumstances is unnecessary, particularly since any NO_X cap and trade program being evaluated will have to go through notice and comment in order to be included in a State Implementation Plan or Federal Implementation Plan. Newspaper notice would also be unworkable in light of the number of units and States (e.g., all Phase II, Group 1 and Group 2 units in the 37–State OTAG area) that could be involved.

The provisions for public comment period and public hearing are essentially the same as those in part 72. Notice must be given of the final decision in the same manner as notice of the draft decision. Any appeals of the final decision are governed by part 78, which governs other Acid-Rain-related decisions of the Administrator.

Finally, after the Administrator decides to relieve units of the section 407(b)(2) limits in light of a given cap and trade program, the State Implementation Plan or Federal Implementation Plan could potentially be revised in a way that may affect the cap and trade program and the basis for the Administrator's decision. In such circumstances, the Administrator may reconsider the decision to grant relief from the section 407(b)(2) limits. The ability to reconsider is explicitly preserved in the rule in order to ensure that the environmental benefit of the section 407(b)(2) limits that would otherwise apply to the units involved continues to be realized.

A number of commenters addressed whether NO_X trading should be established, along with the emission limits and other provisions of part 76, as part of the title IV NO_X program itself. Although many commenters supported NO_X trading and urged generally that EPA has legal authority to implement a title IV NO_X trading program, only limited specific legal justification was provided. One commenter argued that EPA lacks such title IV legal authority while another suggested that means of accounting for reductions below the title IV emission limits be established so that credit for such excess reductions could be used in NO_X trading under title I. Further, some commenters supported title IV NO_X trading following the Open Market Trading approach with discrete emission reduction credits while other commenters supported a title IV NO_X cap and trade program similar to the SO_2 cap and trade program and opposed the Open Market Trading approach. One commenter suggested that credits be given for excess reductions below some target emission rate levels (lower than the title IV emission limits) and that utilities be allowed to use those credits to meet the title IV emission limits.

In light of the comments, EPA has decided to address—through the above-discussed § 76.16—the coordination of cap and trade programs established under title I with the emission limits established under title IV and not to address NO_X trading under title IV itself at this time. Substantial questions have been raised concerning the authority to establish NO_X trading under title IV because of specific language in, and the legislative history of, section 407. *See, e.g.,* 59 FR 13561–62. These concerns do not apply to title I, under which significant progress has been made toward establishing NO_X cap and trade programs, *e.g.,* by the OTC and OTAG. The approach under § 76.16 will build on and encourage these efforts by integrating title I cap and trade programs with the title IV emission limit program in a way that achieves necessary NO_X reductions in a cost effective manner. Further, the approach in § 76.16 avoids creating multiple, potentially overlapping NO_X cap and trade programs under different sections of the Clean Air Act. As already noted, EPA recognizes that, in cases where the Administrator exercises his or her full discretion under § 76.16, Group 1 boilers subject to a title I cap and trade program will still be subject to the existing Group 1 limits under title IV. To the extent that this significantly limits the benefits of cap and trade, the Agency may consider additional actions, consistent with the Clean Air Act, that will enable affected units to meet NO_X emission limitation requirements by using cap and trade programs that provide at least equivalent environmental benefits.

IV. Administrative 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 docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can effectively participate in the rulemaking process. Along with the preamble of the proposed and final rule and EPA responses to significant comments, the contents of the docket will serve as the record in case of judicial review to the extent provided in section 307(d)(7)(A).

B. Executive Order 12866

Under Executive Order 12866 (58 FR 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 $204 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. A detailed breakdown of the total cost and the corresponding NO_X reductions is presented in Table 17.

TABLE 17.—APPROX. PHASE II NO_X Rule Cost and Reductions by Boiler Type

[Including Averaging and AELs]

Boiler type	NO_X reduction (tons/year) [27]	Total cost (annualized $)	Cost-effectiveness ($/ton)
Dry Bottom Wall-Fired	90,000	22,000,000	244
Tangentially Fired	30,000	18,000,000	600
Cell Burner	420,000	33,000,000	79
Cyclone (>155MWe)	225,000	89,000,000	396
Wet Bottom (>65MWe)	80,000	35,000,000	438
Vertically Fired	45,000	7,000,000	156
Total	890,000	204,000,000	229

[27] Reductions projected, not true contribution of the emission limitations for each boiler type to total reductions. With averaging, the more cost-effective boiler types to control will reduce more than required to meet their individual emission limits and the less cost-effective boiler types will reduce less than required by their individual limits.

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.

Commenters have expressed general concern regarding certain aspects of the Regulatory Impact Analysis to the proposed rule. Issues raised include the concern that: (1) The RIA failed to examine the costs and impacts of a wider variety of options; (2) EPA underestimated the number and costs of AEL applications; (3) costs for the proposed revised Group 1 limits are less than costs specified in the April 13, 1995 rule; and (4) the RIA does not adequately address the risks of decreased marketability of flyash.

In the RIA for the final rule, EPA analyzed two additional options which considered economic and environmental impacts of the final rule, totaling five options. These two additional options include: (1) No revisions to the Phase I, Group 1 emission limits; and (2) no emission limits for wet bottom or cyclone boilers. The inclusion of these two options addresses comments that more options should be investigated in the RIA.

In all the options considered, EPA assigned a cost to the AEL process of $225,000. This cost is consistent with utility projections and projections made during the April 13, 1995 NO_X rule. The cost of controls used in the RIA were developed in reports presented in docket items IV–A–1, IV–A–2, IV–A–4, IVA–6, and V–B–1. These reports were produced from previous EPA studies and comments received during the comment period of the proposed rule. EPA's model projects an additional 50 AELs for Group 1 and Group 2, as a result of today's final rule.

The RIA does not attribute a cost to flyash marketability because: (1) The revision of the Group 1 limits is based on the same basic technology (i.e., low NO_X burner technology) already considered in the April 13, 1995 rule and does not impose any additional NO_X control technology requirements relevant to flyash; (2) the impacts to flyash marketability from Group 2 boiler limits are minimal since the majority of these boilers sell bottom ash, not flyash; and (3) as discussed in the proposed rule (61 F.R. 1467), there are currently low cost technologies that minimize, or in some cases eliminate, unburned carbon (the main by-product affecting flyash marketability) from flyash.

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 0.20 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'') 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: (1) Identification of the federal law under which the rule is promulgated; (2) 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; (3) if feasible, estimates of the future compliance costs and any disproportionate budgetary effects of the mandate; (4) if feasible, estimates of the effect on the national economy; and (5) 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.

Many utilities have expressed concern that EPA did not consider for the proposed rule all possible options, including the option of ''no revision'' for Group 1 boilers. Concern was also expressed regarding the discrepancy between the budgetary impact statement which is based on the proposed rule's preferred Option 2–80 (which excludes cyclones with a generating capacity below 80 megawatts), and the proposed rule language which did not explicitly exempt cyclone boilers below 80 megawatts. Others questioned the appropriateness of cost data and whether EPA properly addressed State and local government issues.

For the final rule, EPA investigated new ways to minimize the impact of the final rule on State, local government, and privately owned utilities while carrying out the requirements of section 407. These investigations, prompted by comments received during the public comment period and by consultations with affected entities include: (1) Investigation of what, if any, requirements of the rule imposed an inordinately high burden on any specific utility; and (2) investigation of incremental environmental and economic impacts of varying the size cutoff for wet bottom and cyclone boilers affected by this rulemaking. The results of these investigations were used in developing the emission limits and applicability requirements that are now being promulgated.

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 the final rule, the Agency discusses several regulatory options and their associated costs. As discussed above, the Agency has considered other regulatory options beyond the options discussed in the proposal.

In the final rule, EPA expands the number of regulatory options that are considered and selects the one that is the least cost, most cost-effective, or least burdensome alternative that is consistent with the objectives of the rule. Option 1 is the revision of the Group 1 emission limits and no establishment of Group 2 emission limits. Option 2 is no revision of Group 1 limits and the establishment of limits for all Group 2 boilers, except stokers and fluidized bed combustion (FBC) boilers. Option 3 is the revision of the Group 1 limits and the establishment of limits for all Group 2 boilers, except stokers and FBC boilers. Option 4 is the revision of the Group 1 limits and the establishment of limits for all Group 2 boilers except cyclones with capacity of 155 MWe or less, wet bottoms with capacity of 65 MWe of less, stokers, and FBC boilers. Option 5 is the revision of the Group 1 limits and the establishment of limits for all Group 2 boilers except cyclones, wet bottoms, stokers, and FBCs.

EPA has determined that of these options, only Option 4 is consistent with the purposes of the rule. Under section 407(b)(2) of the Act, the Administrator may revise the Group 1 limits if more effective low NO_X burner technology is available for Group 1 boilers. If EPA determines that more effective low NO_X burner technology is available, section 407(b)(2) does not specify the criteria to be used in determining whether to adopt more stringent Group 1 limits. However, consistent with the environmental purposes of title IV and the Clean Air Act in general and in light of the likely need to make significant, regional NO_X reductions, EPA has decided that it should exercise its discretion and that the objective of the rule should be to adopt more stringent Group 1 limits. Consequently, regulatory options under which the Group 1 limits would not be revised (i.e., Option 2) are inconsistent with the objectives of the rule. Further, under section 407(b)(2), the Administrator must set emission limits for all Group 2 boilers based on degree of reduction achievable using the best system of continuous emission reduction and with comparable cost to low NO_X burner technology on Group 1 boilers. In setting the limits, available technology, costs, and energy and environmental impacts must be considered. EPA has determined that there are available control technologies of comparable cost-effectiveness to that of low NO_X burner technology on Group 1 boilers for cell burners, cyclones greater than 155 MWe, wet bottoms greater than 65 MWe, and vertically fired boilers (except for arch-fired boilers) and that the objective of the rule is to set limits for such boilers. Consequently, regulatory options that do not set limits for each of these Group 2 boiler categories (e.g., Options 1 and 5) or that set limits for all cyclones and wet bottoms (e.g., Options 2 and 3) are not consistent with the objectives of the rule.

EPA concludes, for the reasons discussed above, that Option 4 is the only option that is consistent with the objectives of the rule. EPA also notes that the size cutoffs for cyclones and wet bottoms were established both to limit the boilers covered to the group for which the applicable control technologies were of comparable cost effectiveness to LNBs on Group 1 boilers and to limit the number of municipally owned boilers covered by the emission limits. While the cutoffs could have been set at lower levels if only comparability of cost effectiveness were considered, the cutoffs were adjusted in order to exempt certain municipally owned boilers that were close to the potential cutoff points, while having only a minimal impact on the total amount of NO_X reductions that would be realized. Adopting lower cutoffs would increase the impact of the rule on municipal utilities and result in limited additions in NO_X reductions. Under these circumstances, EPA maintains that, in selecting Option 4, the Agency is choosing the least costly, most cost effective, or least burdensome alternative that is consistent with the objectives of the rule.

In addition, EPA notes that, considering the alternative approaches under the Clean Air Act for reducing NO_X emissions by utility and non-utility sources, Option 4 represents the most cost effective alternative. Having determined that significant, regional reductions of NO_X emissions are likely to be needed, EPA compared the cost effectiveness of alternative approaches for reducing NO_X emissions, i.e., the cost effectiveness of achieving reductions by coal-fired utility boilers under Option 4, by coal-, oil-, or gas-fired utility boilers using more advanced control technologies than under Option 4, by non-utility stationary sources, and by mobile sources. The reductions under Option 4 are the most cost effective of these alternative approaches and represent a reasonable step toward achieving necessary, regional NO_X reductions.

Because this final 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 final rule is promulgated under section 407(b)(2) of the Clean Air Act. Total expenditures resulting from the rule are estimated at approximately $204 million per year starting in 2000. There are no federal funds available to assist State, local, and tribal governments in meeting these costs. However, title V of the Act authorizes State, local, and tribal permitting authorities to collect permitting fees from utilities to cover all costs of developing and issuing title V operating permits, including Acid Rain provisions reflecting standard NO_X emission limits, AELs, and emissions averaging. Prudent costs incurred in complying with this rule may be recovered by utilities by passing them on to ratepayers. There are important benefits from NO_X emission reductions because atmospheric emissions of NO_X have significant adverse impacts on human health and welfare and on the environment.

The final 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[28]. Further, the rule 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 final rule, EPA evaluated the public comments and concerns, and to the extent consistent with section 407 of the Clean Air Act, those comments and concerns are reflected in the final rule. These procedures ensured State and local governments an opportunity to give meaningful and timely input and to obtain information, education, and advice regarding compliance. Additionally, EPA solicited comments from the 25 State and municipality owned utilities, as well as elected officials of their respective State and local governments. They were provided a summary of the EPA proposal and the estimated impacts.

As described in EPA's analysis (see docket item V–B–1 (RIA, 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 municipally-owned or State-owned utilities, are somewhat 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.

[28] As shown in EPA's Unfunded Mandates Act Analysis, as a result of this proposal, State and municipality owned boilers experience average control costs of 0.024 mills/kWh while the national average control costs are 0.125 mills/kWh.

D. Paperwork Reduction Act

This final rule does not impose any information collection requirements subject to the Paperwork Reduction Act, (44 U.S.C. 3501, et seq.) not already required under the current provisions of part 75 and part 76 over the next three years. Before the year 2000, the year in which these emission limits take effect, EPA will submit an Information Collection Request renewal to OMB. The additional burden hours, if any, will reflect the compliance of the Group 2 boilers subject to this rule.

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 entities. It has been determined that this is a major rulemaking because it will have an annual effect on the economy of approximately $204 million.

Some commenters question the accuracy of cost and impact data, as well as whether EPA should exempt, or moderate the burden on, certain units that would have difficulty complying with the proposed limits, such as older or smaller units. As elaborated in the Small Entity Screening Analysis for the final rule, (see docket item V–B–1), EPA investigated new ways to minimize the impact of the final rule on State, local government, and privately owned utilities while carrying out the requirements of section 407. These investigations, prompted by comments received during the public comment period and by consultations with the affected industries, included investigation of what, if any, requirements of the rule imposed an inordinately high burden on any specific small business entity. The results of this investigation were used in developing the emission limits and applicability requirements that are now being promulgated.

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.

Of the estimated 700 small utilities (including small investor-owned, cooperative, or municipally owned utilities) in the U.S., 64 are subject to part 76, and of these, only 15 are expected to incur any compliance costs as a result of this final rule. For this reason alone, this rule will not have significant adverse impact on a substantial number of small entities. EPA notes that it also analyzed in detail the potential impact of the final rule on various financial measures of the 15 adversely impacted small utilities' profitability and short- and long-term solvency. The results show that, though the financial impact of compliance with this rule for the 15 small utilities is greater than that for medium and large utilities, the impact of the rule, as reflected in changes in various financial measures (such as return on equity and return on assets), is not significant (see docket item V–B–1 (RIA, EPA's Small Entity Screening Analysis)).

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule. EPA has determined that this rule will have no significant adverse effect on a substantial number of small entities.

F. Submission to Congress and the General Accounting Office

Under 5 U.S.C. 801(a)(1)(A) as added by the Small Business Regulatory Enforcement Fairness Act of 1996, EPA submitted a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives and the Comptroller General of the General Accounting Office prior to publication of the rule in today's Federal Register. This rule is a ''major rule'' as defined by 5 U.S.C. 804(2).

G. 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 10, 1996.

Carol M. Browner,

Administrator.

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, in alphabetical order, definitions for ''arch-fired boiler'', ''boiler capacity'', ''coal-fired utility boiler'', ''combustion controls'', ''fluidized bed combustor boiler'', ''maximum continuous steam flow at 100% of load'' ''non-plug-in combustion controls'', ''plug-in combustion controls'', and ''vertically fired boiler'', to read as follows:

§ 76.2 Definitions.

* * * * *

Arch-fired boiler means a dry bottom boiler with circular burners, or coal and air pipes, oriented downward and mounted on waterwalls that are at an angle significantly different from the horizontal axis and the vertical axis. This definition shall include only the following units: Holtwood unit 17, Hunlock unit 6, and Sunbury units 1A, 1B, 2A, and 2B. This definition shall exclude dry bottom turbo fired boilers.

* * * * *

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.

* * * * *

Maximum Continuous Steam Flow at 100% of Load means the maximum capacity of a boiler as reported in item 3 (Maximum Continuous Steam Flow at 100% Load in thousand pounds per hour), Section C (design parameters), Part III (boiler information) of the Department of Energy's Form EIA–767 for 1995.

* * * * *

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 roof-fired boilers and dry bottom top-fired boilers, and shall exclude dry bottom arch-fired boilers and 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 remaing paragraph (g).

4. Section 76.6 is revised 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, or a vertically 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 §§ 76.10 or 76.11:

(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 after November 15, 1990 shall comply with the emission limitation applicable to cell burner boilers. The owner or operator of a unit with a cell burner that installs non-plug-in combustion controls on or before November 15, 1990 shall comply with the applicable emission limitation for dry bottom wall-fired boilers.

(2) 0.86 lb/mmBtu of heat input on an annual average basis for cyclone boilers with a Maximum Continuous Steam Flow at 100% of Load of greater than 1060 lb/hr. The NO_X emission control technology on which the emission limitation is based is natural gas reburning or selective catalytic reduction.

(3) 0.84 lb/mmBtu of heat input on an annual average basis for wet bottom boilers, with a Maximum Continuous Steam Flow at 100% of Load of greater than 450 lb/hr. The NO_X emission control technology on which the emission limitation is based is natural gas reburning or selective catalytic reduction.

(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.

(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 amended by adding paragraphs (a) and (b) 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, 76.10, or 76.11:

(1) 0.40 lb/mmBtu of heat input on an annual average basis for tangentially fired boilers.

(2) 0.46 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.

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 for Group 1 boilers 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''.

8. Section 76.16 is added to read as follows:

§ 76.16 Alternative compliance.

(a)(1) A State or group of States may submit a petition requesting that the Administrator, or the Administrator, on his or her own motion, may:

(i) Require the owners or operators of the Group 1, Phase II coal-fired utility units with a tangentially fired boiler or a dry bottom wall fired boiler in the State or the group of States to be subject to the applicable emission limitations for NO_X in § 76.5, in lieu of the applicable emission limitations for NO_X in § 76.7; and

(ii) Provide that the owners or operators of the Group 2 coal-fired utility units with a cell burner boiler, cyclone boiler, wet bottom boiler, or vertically fired boiler in the State or the group of States are not subject to the applicable emission limitations for NO_X in § 76.6.

(2) A petition under paragraph (a)(1) of this section must demonstrate that the requirements in paragraphs (b)(1) and (2) of this section are met.

(3) A petition under paragraph (a)(1) of this section may be submitted, but may not be approved by the Administrator, before the State Implementation Plan or Federal Implementation Plan covering the entire State or the State Implementation Plans or Federal Implementation Plans covering the entire group of States become final and federally enforceable.

(b) The Administrator may take the actions set forth in paragraphs (a)(1)(i) and (ii) of this section if he or she finds that, under the State Implementation Plan or Federal Implementation Plan covering the entire State or the State Implementation Plans or Federal Implementation Plans covering the entire group of States:

(1) Each unit that is in the State or the group of States and that, but for the provisions of this section, would be subject to emission limitations under this part

(i) Is subject to a cap on total annual NO_X emissions or two or more seasonal caps that together limit total annual NO_X emissions;

(ii) May trade authorizations to emit NO_X within each such cap; and

(iii) Must use NO_X emission authorizations to account for the NO_X emissions by such unit and to account for the NO_X emissions resulting from reducing utilization of such unit below its baseline utilization (adjusted for changes in demand for electricity) and shifting utilization to any other unit, or combustion device serving a generator that produces electricity for sale, that is not subject to each such cap; and

(2)(i) Total annual NO_X emissions by all units that are in the State or the group of States and that, but for the provisions of this section, would be subject to emission limitations under this part will be lower than total annual NO_X emissions by such units if each such unit is treated as subject to the applicable emission limitation in §§ 76.5, 76.6, or 76.7 that would apply but for the provisions of this section.

(ii) In the case of a petition under paragraph (a) of this section, total annual NO_X emissions by the units will be determined using the actual utilizations of the units for the last full calendar year prior to submission of the petition but, in any event, for no later than 1999. In the case of action by the Administrator on his or her own motion under paragraph (a) of this section, total annual NO_X emissions by the units will be determined using the actual utilizations of the units for the last full calendar year prior to issuance of the draft decision under paragraph (c) of this section, but, in any event, for no later than 1999.

(c) In acting on a petition or on his or her own motion under paragraph (a) of this section, the Administrator will issue for public comment a draft decision on the petition or a draft decision to act on his or her own motion and then a final decision. The Administrator may issue a draft decision, but not final decision, on a petition or on his or her own motion before the State Implementation Plan or Federal Implementation Plan covering the entire State or the State Implementation Plans or Federal Implementation Plans covering the entire group of States become final and federally enforceable. The draft decision will set forth procedures that will govern issuance of the final decision and will provide for:

(1) Service of notice of issuance of the draft decision on.

(i) Any interested person;

(ii) The air pollution control agencies that have jurisdiction over a unit covered by the draft decision, are in a State whose air quality may be affected by the draft decision and that is contiguous to a State in which such a unit is located, or are in a State that is within 50 miles of a unit covered by the draft decision; and

(iii) On any federally recognized Indian Tribe in an area in which a unit covered by the draft decision is located, whose air quality may be affected by the draft decision and that is in an area that is contiguous to a State in which such a unit is located, or that is in an area that is within 50 miles of a unit covered by the draft decision;

(2) Publication of notice of issuance of the draft decision in the Federal Register and in any State publication designed to give general public notice in the States in which the units covered by the draft decision are located;

(3) A 30-day public comment period and extension or reopening of the comment period by the Administrator for good cause;

(4) A public hearing, upon request or on the Administrator's own motion, to the extent the Administrator determines that a public hearing will contribute to the decision-making process by clarifying one or more significant issues affecting the draft decision;

(5) Consideration by the Administrator of the comments on the draft decision received during the public comment period or any public hearing and written response by the Administrator to any such relevant comments;

(6) Notice of issuance of a final decision using the methods set forth in paragraphs (c)(1) and (2) of this section for providing notice of the draft decision; and

(7) Appeals, governed by part 78 of this chapter, of the final decision.

(d) If, after the Administrator issues a final decision under paragraph (c) of this section and takes the actions set forth in paragraphs (a)(1)(i) and (ii) of this section with regard to a State or group of States, a State Implementation Plan or Federal Implementation Plan covering the entire State or entire group of States is revised in a way that may affect the basis for the findings on which such decision is based, the Administrator may, upon petition or on his or her own motion, reconsider such decision.

(e) For purposes of this section, the term ''State'' shall mean one of the 48 contiguous States or the District of Columbia.

Appendix B to Part 76 [Amended]

9. Appendix B is amended by: removing from the heading 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 word ''cost''; removing from section 1 the words ''average capital costs and cost-effectiveness'' and adding, in their place, the words ''capital costs and cost effectiveness''; removing from section 1 the words ''as determined in section 3 below''; removing from section 1 the words ''only overfire air'' and adding, in their place, the words ''overfire air''; removing from section 1 the words ''only separated overfire air'' and adding, in their place, the words ''separated overfire air''; removing from, the heading section 1 and the introductory text of section 2 the words ''Group 1, Phase I'' in each place that the words appear and adding, in their place, the words ''Group 1''; removing section 2.4; and removing and reserving section 3.

[FR Doc. 96–31839 Filed 12–18–96; 8:45 am]

BILLING CODE 6560–50–P