FOR FURTHER INFORMATION CONTACT: Daniel A. Meer, Chief, Rulemaking Section, Air and Toxics Division, U.S. Environmental Protection Agency, Region IX, 75 Hawthorne Street, San Francisco, CA 94105, Telephone: (415) 744–1185.

SUPPLEMENTARY INFORMATION

Background

On June 2, 1994 in 59 FR 28503 EPA proposed to approve the following rules into the California SIP: SCAQMD's Rule 1106.1, Pleasure Craft Coating Operations, and Rule 109, Recordkeeping for Volatile Organic Compound Emissions. Rule 1106.1 was adopted by SCAQMD on May 1, 1992, and Rule 109 was adopted on March 6, 1992. Both rules were submitted by the California Air Resources Board (CARB) to EPA on September 14, 1992. These rules were submitted in response to EPA's 1988 SIP-Call and the CAA section 182(a)(2)(A) requirement that nonattainment areas fix their reasonably available control technology (RACT) rules for ozone in accordance with EPA guidance that interpreted the requirements of the pre-amendment Act. A detailed discussion of the background for each of the above rules and nonattainment areas is provided in the NPR(s) cited above.

EPA has evaluated the above rules for consistency with the requirements of the CAA and EPA regulations and EPA interpretation of these requirements as expressed in the various EPA policy guidance documents referenced in the NPR(s) cited above. EPA has found that the rules meet the applicable EPA requirements. A detailed discussion of the rule provisions and evaluations has been provided in [59 FR 28503 and in technical support documents (TSDs) available at EPA's Region IX office (TSDs dated February 16, 1993, Pleasure Craft Coating Operations and February 24, 1993, Recordkeeping for Volatile Organic Compound Emissions).

Response to Public Comments

A 30-day public comment period was provided in 59 FR 28503. EPA received no comments.

EPA Action

EPA is finalizing action to approve the above rules for inclusion into the California SIP. EPA is approving the submittal under section 110(k)(3) as meeting the requirements of section 110(a) and Part D of the CAA. This approval action will incorporate these rules into the federally approved SIP. The intended effect of approving these rules is to regulate emissions of VOCs in accordance with the requirements of the CAA.

Nothing in this action should be construed as permitting or allowing or establishing a precedent for any future request for revision to any state implementation plan. Each request for revision to the state implementation plan shall be considered separately in light of specific technical, economic, and environmental factors and in relation to relevant statutory and regulatory requirements.

The Office of Management and Budget (OMB) has exempted this action from review under Executive Order 12866.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Hydrocarbons, Incorporation by reference, Intergovernmental relations, Ozone, Reporting and recordkeeping requirements, Volatile organic compounds.

Note: Incorporation by reference of the State Implementation Plan for the State of California was approved by the Director of the Federal Register on July 1, 1982.

Dated: March 28, 1995.

Felicia Marcus,

Regional Administrator.

Part 52, chapter I, title 40 of the Code of Federal Regulations is amended as follows:

PART 52—[AMENDED]

1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart F—California

2. Section 52.220 is amended by adding paragraph (c)(189)(i)(A)(*6*) to read as follows:

§ 52.220 Identification of plan.

* * * * *

(c) * * *

(189) * * *

(i) * * *

(A) * * *

(*6*) Rule 109 adopted on March 6, 1992, and Rule 1106.1 adopted on May 1, 1992.

* * * * *

[FR Doc. 95–9042 Filed 4–12–95; 8:45 am]

BILLING CODE 6560–50–P

40 CFR Part 76

[AD–FRL–5186–5]

RIN 2060–AD45

Acid Rain Program: Nitrogen Oxides Emission Reduction Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule; response to court remand.

SUMMARY: The EPA is today issuing this final rule in response to a remand by a U.S. Court of Appeals. The rule reinstates emission limitations for nitrogen oxides (NO_X) from coal-fired utility units under section 407 of the Clean Air Act (''the Act''). The emission limitations for NO_X, along with emission limitations for sulfur dioxide from utility plants, will reduce acidic deposition and its serious adverse effects on natural resources, ecosystems, materials, visibility, and public health.

On March 22, 1994, EPA promulgated a rule establishing NO_X emission limitations. The rule established emission limits generally achievable using ''low NO_X burner technology'' and established a procedure for obtaining an alternative emission limitation (AEL) if a unit could not achieve the prescribed limit using such technology. On November 29, 1994, the U.S. Court of Appeals for the District of Columbia Circuit ruled that the definition of ''low NO_X burner technology'' in the March 22, 1994 rule exceeded EPA's statutory authority. The Court vacated the rule and remanded it to the Agency for further proceedings. On March 28, 1995, EPA and environmental and utility-industry parties signed an agreement addressing the March 22, 1994 regulations, including issues raised by the Court's remand.

Based on the Court's decision and a review of the record, the Agency is now revising the March 22, 1994 regulations. The low-NO_X-burner-technology definition is revised to comply with the Court's decision. Other provisions concerning the compliance date for Phase I NO_X emission limitations, AELs, and plans for averaging NO_X emissions of two or more units are also revised. In general, the revisions reduce compliance requirements, extend the compliance date, and increase compliance flexibility. The rule revisions are issued as a direct final rule because they are consistent with the Court's decision and no adverse comment is expected. The revisions are also consistent with the March 28, 1995 agreement.

EFFECTIVE DATE: This direct final rule will be effective on May 23, 1995 unless significant, adverse comments are received by May 15, 1995. If significant, adverse comments are timely received on any portion of the direct final rule, that portion of the direct final rule will be withdrawn through a notice in the Federal Register.

The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of May 23, 1995.

ADDRESSES: Docket No. A–92–15, containing information considered during development of the promulgated standards and requirements, 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 (6102), Waterside Mall, Room M1500, 1st Floor, 401 M Street, SW., Washington, DC 20460. A reasonable fee may be charged for copying. Additional data and information pertaining to the rule may be found in Docket No. A–90–39.

FOR FURTHER INFORMATION CONTACT: Peter Tsirigotis, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M Street SW., Washington, DC 20460 (for technical matters) at (202) 233–9620; or Dwight C. Alpern (same address) (for legal matters) at (202) 233–9151.

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

I. Background

A. Purpose of the Acid Rain NO_X Program

The purpose of the Acid Rain NO_X emission reduction program is to reduce the adverse effects of acidic deposition on natural resources, ecosystems, visibility, materials, and public health by substantially reducing annual emissions of NO_X from coal-fired electric utilities. 42 U.S.C. 7651(a)(1). NO_X, along with sulfur dioxide, is a principal precursor of acidic deposition.

Although sulfate deposition is considered to be the major contributor to long-term aquatic acidification, nitric acidic deposition plays a dominant role in the ''acid pulses'' associated with the fish kills observed during the springtime meltdown of the snowpack in sensitive watersheds. Furthermore, the atmospheric deposition of NO_X is a substantial source of nutrients that damage estuaries, such as the Chesapeake Bay, by causing algae blooms and anoxic conditions. Nitrogen dioxide and particulate nitrate also contribute to pollutant haze. Moreover, acidic deposition and ozone (formed by the photochemical reaction of NO_X and volatile organic compounds) contribute to the premature weathering and corrosion of building materials such as architectural paints and stones.

Electric utilities are a major contributor to NO_X emissions nationwide; in 1980, they accounted for 30 percent of total NO_X emissions and, by 1990, their contribution rose to 38 percent of total NO_X emissions. Approximately 80 percent of electric utility NO_X emissions come from coal-fired plants of the type addressed by section 407 of the Act.

B. Statutory Framework

Section 407(b)(1) of the Act requires the Administrator to establish NO_X emission limitations for two types of coal-fired utility boilers (''Group 1'' boilers): (1) Tangentially fired boilers; and (2) dry bottom wall-fired boilers other than units applying cell burner technology (''wall-fired boilers''). The Act specifies the maximum emission limits (often referred to as ''presumptive'' emission limits or limits) for these Group 1 boilers: 0.45 lb/mmBtu for tangentially fired boilers; and 0.50 lb/mmBtu for wall-fired boilers. If the Administrator finds that the presumptive limits cannot be achieved using ''low NO_X burner technology,'' the Administrator may set less stringent limitations. 42 U.S.C. 7651f(b)(1). A Phase I coal-fired utility unit with a Group 1 boiler must comply with the promulgated annual NO_X emission limitation on the later of January 1, 1995 or the date the unit is required to meet SO_2 emission reduction requirements under section 404(d) of the Act (*id.*).

Section 407(d) provides a mechanism by which a utility unit may receive an AEL less stringent than the applicable limitation established under section 407(b)(1) for Group 1 boilers. In order to receive an AEL, the owner or operator of the unit must demonstrate that it cannot meet the applicable limitation using properly installed ''low NO_X burner technology'' designed to meet the limitation. 42 U.S.C. 7651f(d). If the owner or operator makes the necessary showings, then an AEL will be established that does not require ''any additional control technology beyond low NO_X burners.'' 42 U.S.C. 7651f(d).

Section 407(d) also provides that EPA may grant the owner or operator of a Phase I coal-fired utility unit subject to section 407(b)(1) a 15-month extension from the January 1, 1995 compliance deadline. Such an extension may be granted if the technology necessary to meet the promulgated NO_X emission limitation is not in adequate supply to enable its installation and operation at the unit, consistent with system reliability, by January 1, 1995. Section 407(d) specifies the process the Administrator must use in authorizing the Phase I extension.

A more detailed discussion of the statutory framework is set forth at 59 FR 13538–13539 (March 22, 1994).

C. EPA's Rulemaking

As discussed above, the term ''low NO_X burner technology'' plays an important role in section 407 of the Act. There has been substantial controversy as to whether Congress intended ''low NO_X burner technology'' to be equivalent to ''low NO_X burners'' and whether ''low NO_X burner technology'' includes all forms of combustion air staging or only staging at the burner. On November 25, 1992, EPA published a proposed rule establishing NO_X emission limitations for coal-fired utility units under section 407(b)(1) of the Act and other requirements and procedures for all coal-fired units subject to Phase I and Phase II of the Acid Rain Program (57 FR 55632–55683). In recognition of the controversy surrounding the definition of low NO_X burner technology, the proposed rule contained two regulatory options and an alternative approach for defining that term. Option 1 defined low NO_X burner technology as low NO_X burners incorporating overfire air for wall-fired boilers and as low NO_X burners incorporating separated overfire air (e.g., LNCFS 2 and LNCFS 3) for tangentially fired boilers (57 FR 55642). Option 2 defined low NO_X burner technology as low NO_X burners incorporating separated overfire air for tangentially fired boilers, but excluded overfire air from the definition for wall-fired boilers (*id.*). In addition to the two options set forth, EPA solicited comment on a third approach. This approach was endorsed by the Utility Air Regulatory Group (UARG) (a group made up of utilities that subsequently challenged the March 22, 1994 final rule) and the U.S. Department of Energy (DOE). Under the third approach, low NO_X burner technology was defined as excluding both overfire air for wall-fired boilers and separated overfire air for tangentially fired boilers (57 FR 55644–55645).

On March 22, 1994, EPA published the final NO_X rule (59 FR 13538–13580). In that rule, EPA adopted the Option 1 definition of low NO_X burner technology after considering the chemical process of low NO_X combustion, the history and application of low NO_X combustion technology, Congress' intent in section 407 of the Act, and the actual application of NO_X control technology.

II. The Court's Decision

Following issuance of the March 22, 1994 rule, numerous utilities and the National Coal Association petitioned for judicial review of the rule. The two main issues raised on appeal were: whether EPA's definition of low NO_X burner technology was lawful; and whether EPA was obligated to extend the January 1, 1995 compliance date prescribed in section 407 of the Act because EPA did not issue the rules by the May 15, 1992 issuance date required by section 407.

On November 29, 1994, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision on the petitioners' first issue. The Court held that ''[t]he statutory text, structure, and history of section 407 * * * support the 'unmistakable conclusion' that Congress unambiguously intended the term 'low NO_X burner technology' to encompass only low NO_X burners, not overfire air'' (*Alabama Power Co.* v. *U.S. EPA*, No. 94–1170 (D.C. Cir, 1994) slip op. at 12). The Court explained that under the AEL provision, ''Congress did not intend to require utilities to consider the 'full range of low NO_X combustion technologies' because it *expressly* provided that utilities not be required to install or use any equipment beyond low NO_X burners in their efforts to comply with NO_X emission limits'' (*id.* at 11). After concluding that EPA had exceeded its statutory authority, the Court vacated the March 22, 1994 rule and determined that the petitioners' second issue on the compliance deadline was moot.

III. EPA's Response to the Court's Decision

A. Changes to the March 22, 1994 Rule

1. Definitions

Low NO_X burners and low NO_X burner technology. Because the Court determined that, in defining low NO_X burner technology in the March 22, 1994 rule, the Agency exceeded its authority under section 407 of the Act, the revised rule changes the definition of the terms, ''low NO_X burners and low NO_X burner technology,'' in § 76.2. The Court determined that low NO_X burner technology encompasses ''only low NO_X burners'' (*Alabama Power*, slip op. at 12). The Agency is removing from the March 22, 1994 definition the language that is inconsistent with the Court's determination. In particular, the revised rule eliminates the language stating that low NO_X burner technology includes ''any combination of coal and air nozzles ports * * * not restricted to location within the boiler, including * * * NO_X ports, overfire air ports, or staged combustion ports'' (59 FR 13565). Other related language (e.g., ''at points downstream of the initial flame'' (*id.*)) in the March 22, 1994 definition is also removed.

The removed language is replaced by new language explaining that the new definition includes the staging of combustion air using air nozzles or registers located inside any boiler waterwall[1] hole that includes a burner. Additional new language explains that the definition excludes the staging of combustion air using air nozzles or ports located outside any boiler waterwall hole that includes a burner. The new language implements, for both wall- and tangentially-fired boilers, the Court's holding that low NO_X burner technology includes only low NO_X burners.

For wall-fired boilers, two types of NO_X combustion controls have been used: (1) Advanced burner retrofits for reducing NO_X formation (''burner retrofits'');[2] and (2) combustion air staging (i.e., ''overfire air'' for wall-fired boilers) (57 FR 55640). Burner retrofits must be custom-designed for each boiler and the ease of retrofitting varies from boiler to boiler:

> In some cases (of burner retrofits), burner openings must be enlarged via remolding the refractory material at the burner exit or by enlarging the hole (*not* cutting holes in the boiler tubes). If enlargement of the hole requires that tubes be cut and bent slightly to accommodate the burner, however, this procedure does not affect the boiler water circulation since the tubes have been previously bent. The circulation design takes bends into account during initial boiler design. By contrast, cutting holes as required for the addition of (overfire air) affects the boiler circulation. (Docket Item VIII–A–2, Reply Brief of Petitioners, August 29, 1994, Exhibit 1.)

Unlike burner retrofits, overfire air for wall-fired boilers involves diverting some combustion air from waterwall openings that include a burner and injecting the air above the top burner level. This generally requires the cutting of entirely new holes in the waterwall above the highest burners (*id.*; 57 FR 55640).

The new low-NO_X-burner-technology definition, as applied to wall-fired boilers, encompasses all burner retrofits that are essentially within an existing waterwall hole. Such retrofits may involve minor modifications (e.g., of pressure parts or refractory material) to the existing waterwall hole as necessary to accommodate the retrofit essentially within the hole. The new definition excludes all overfire air as applied to wall-fired boilers. This definition meets the Court's requirement that only burners be considered; nothing in the Court's decision excludes retrofit burners requiring minor waterwall modifications. *See, e.g.*, slip op. at 5 footnote 3 (discussing low NO_X burners).

For tangentially fired boilers, all commercially available systems for reducing NO_X formation involve a staged combination of coal and air (57 FR 55641). Three types of control systems for tangentially fired boilers were discussed in detail in the preamble to proposed part 76: (1) The replacement of the original coal and air nozzle array in each corner of the boiler with a new low NO_X configuration of coal and air nozzles and the installation of air nozzles at the upper end of each waterwall hole that contains the new coal and air nozzle array (''LNCFS 1'');[3]

[1] Waterwalls are panels of water tubes running along the length of a boiler. These tubes carry water or steam. Water in these tubes is converted into steam through the heat transfer between combustion gas and this water.

[2] Typical designs of burner retrofits include upgraded air registers that allow for better control of combustion air and a redesigned burner tip. Burner retrofits achieve controlled fuel and air mixing in the flame. This arrangement results in rapid devolatilization and combustion of nitrogen-containing volatile matter under conditions of limited availability of oxygen, with the result that the formation of fuel NO_X is suppressed. The arrangement also results in combustion of air and coal char with a cooler flame than the flame of conventional burners, which suppresses thermal NO_X formation (59 FR 13541).

[3] Several other low NO_X burner designs also use combustion air staging in the waterwall hole where

Continued

(2) the installation of air nozzles in a new air nozzle assembly above the waterwall hole that contains the original coal and air nozzle array in each corner (''LNCFS 2''); and (3) the replacement of the original coal and air nozzle array with a new low NO_X configuration in each corner and the installation of both air nozzles at the upper end of each waterwall hole containing the new array and a new air nozzle assembly above each waterwall hole (''LNCFS 3'') (*id.*).

As is the case with wall-fired retrofit burners, LNCFS 1 is custom-designed for each boiler and may require modifications to the existing waterwall hole (59 FR 13546–13547). Retrofit burners and LNCFS 1 respectively involve the injection of air through registers or nozzles located in a waterwall hole that includes the burner: In the case of wall-fired boilers, the air registers are in the burner retrofit itself while in the case of tangentially fired boilers, the air nozzles are in the hole with the coal and air nozzle array.

In contrast with LNCFS 1, LNCFS 2 and LNCFS 3 involve injecting combustion air above the coal and air nozzle array in each corner through a new air nozzle assembly requiring an entirely new waterwall hole above the array (57 FR 55641). The new low-NO_X-burner-technology definition, as applied to tangentially fired boilers, includes the applications of LNCFS 1 (and other low NO_X burner designs)[4] that are essentially within the existing waterwall hole. The included applications may involve minor modifications (e.g., of pressure parts or refractory material) to the existing waterwall hole as necessary to accommodate the NO_X emission controls essentially within the existing hole. The new definition excludes all applications of separated overfire air, e.g., LNCFS 2 and LNCFS 3. This is consistent with the Court's holding in that, as discussed above, LNCFS 1 for tangentially fired boilers is analogous to retrofit burners for wall-fired boilers and thus falls within the Court's prescription that ''low NO_X burner technology'' be limited to low NO_X burners only.

The Agency notes that its new definition is in essence the same as the definition set forth in the preamble of the November 25, 1992 proposed rule as an alternative to Options 1 and 2 (57 FR 55644–55645). The alternative approach, like the new definition adopted today, excluded overfire air for wall-fired boilers and excluded LNCFS 2 and LNCFS 3 for tangentially fired boilers. The utilities described the alternative approach as involving ''the direct replacement of the original equipment manufacturer's coal burners (with low NO_X burners) without major new waterwall penetrations or parts'' (Docket Item IV–D–111 at 74). The utilities also noted that their definition under the alternative approach—like the definition in the revised rule—includes ''burners[-]only technologies that have recently begun to be offered commercially'' for tangentially fired boilers, i.e., the low NO_X burner designs described in footnote 3 above (*id.* at 73). In comments on the November 25, 1992 proposal, the utilities and DOE supported the alternative approach as being consistent with section 407 of the Act (Docket Items IV–D–2 at 1–2 and IV–D–111 at 73–84).

Other defined terms. In light of the new low-NO_X-burner-technology definition adopted today, two other definitions in § 76.2 of the March 22, 1994 rule are now superfluous and are eliminated in the revised rule.[5] In particular, the new low-NO_X-burner-technology definition itself describes what forms of air staging are included or not included in the definition, and, as discussed below, references in other sections of part 76 to ''combustion air staging'' have been removed. Consequently, there is no need for the definition of ''combustion air staging''. See 59 FR 13564. Further, the definition of ''low NO_X coal and air nozzles'' is unnecessary because that term is no longer used in part 76. See 59 FR 13565.

2. Date for Compliance with NO_X Emission Limitations

The revised rule changes the date in § 76.5(a) on which a Phase I unit with a Group 1 boiler begins to be subject to the NO_X emission limitations. Under the March 22, 1994 rule, such a Phase I unit must begin compliance with NO_X emission limitations on the later of January 1, 1995 or the date the unit becomes subject to SO_2 emission reduction requirements under section 404(d) of the Act. Under the revised rule, the January 1, 1995 date is changed to January 1, 1996. Analogous changes in the compliance date are made in §§ 76.1(d) and 76.5(d).[6]

The change in the compliance date is necessary because of the delay in the repromulgation of the NO_X emission limitations. The Court vacated the March 22, 1994 rule on November 29, 1994, only 32 days prior to the compliance deadline. The Court added that the reissued NO_X emission limitations ''will undoubtedly take effect after the statutory deadline [for compliance] of January 1, 1995.'' *Alabama Power,* slip op. at 13. Moreover, the Court noted ''the agency's representation at oral argument that it would be inclined to exercise its enforcement discretion in favor of the utilities in order to account for delay in the rulemaking process'' (*id.*).

As correctly predicted by the Court, today's revised rule reinstating NO_X emission limitations takes effect after January 1, 1995, despite the Agency's efforts to expedite the rulemaking process. Maintaining the January 1, 1995 deadline for compliance with the NO_X emission limitations would mean that the limitations under the revised rule would have to be applied prior to their effective date.

Not only would this approach raise questions of retroactivity, but also the Agency is concerned about the lack of any lead time between promulgation of NO_X emission limitations and the beginning date for compliance. Under these circumstances, the Agency must determine what Congress would have intended had it addressed the problem of issuance of the NO_X emission limitations after January 1, 1995. Section 407 required the Agency to issue final NO_X regulations within 18 months of enactment of title IV (i.e., by May 15, 1992) and required compliance with such regulations to begin on January 1, 1995. Although these are independent requirements and, the Agency maintains, no specific lead time between rule promulgation and compliance was mandated, it is reasonable to conclude that Congress intended that there be some lead time. Retaining a January 1, 1995 compliance deadline would result in no lead time at all.

Further, the Agency recognizes that the promulgation of the March 22, 1994 low-NO_X-burner-technology definition and the Court's decision vacating the March 22, 1994 rule may have

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the coal and air nozzle array is located. Some of these are : Foster Wheeler's T-fired/Split Flame (TF/SF) burner; and International Combustion Ltd.'s FAN burner (Docket Item IV–D–111, Comments of the Utility Air Regulatory Group on EPA's Proposed Rules on Nitrogen Oxides Reduction Program, February 8, 1993, at 28, 30 and 115). Both of these designs incorporate air nozzles at the upper end of the waterwall hole that contains the new coal and air nozzle array in each corner of the boiler. Neither, however, incorporates any staging that utilizes injection of air through separate holes (e.g., separated overfire air ports) in the waterwall and that therefore is external to the waterwall hole containing the burner (*id.* at 27).

[4] See footnote 3 above.

[5] As discussed below, the definition of ''alternative technology'' is also revised.

[6] The language in § 76.5(d) is also revised to make it consistent with § 76.5(a) and clarify that a unit under § 76.5(d) may seek to use a compliance option in §§ 76.10, 76.11, or 76.12.

engendered some uncertainty and confusion on the part of utilities concerning their regulatory obligations. This further supports a change in the January 1, 1995 compliance deadline. However, the Agency notes that Phase I units generally proceeded in good faith to take the necessary steps to comply with the March 22, 1994 rule. These steps included obtaining a permit to operate and, where necessary, installing NO_X control equipment, including low NO_X burners. Of the 175 Phase I units with Group 1 boilers on Table A of section 404, all submitted NO_X compliance plans by May 6, 1994 and only 31 requested a compliance date extension.[7] Since complying with the revised rule will, in general, require the same or less effort than the industry has already undertaken, the extension until January 1, 1996 is judged to be reasonable and appropriate.

The establishment of January 1, 1996 as the compliance deadline also reflects the fact that title IV of the Act created an annual program with regard to both SO_2 and NO_X emissions reductions. Units must comply with SO_2 emission limitations by emitting no more SO_2 in a year than is authorized by the number of allowances ''held for that unit for that year.'' 42 U.S.C. 7651b(g). Similarly, emission limitations for NO_X are annual: The generic limits established under section 407(b) are ''annual allowable emission limitations''; AELs under section 407(d) are emission rates that can be met ''on an annual basis''; and emissions averaging plans under section 407(e) limit NO_X emissions using both ''alternative contemporaneous annual emission limitations'' and a ''Btu-weighted average annual emission rate.'' Adopting January 1, 1996 as the compliance deadline preserves the annual nature of the Acid Rain Program.

The revised rule also changes language in the March 22, 1994 rule concerning the date for compliance with any revised emission limitations for Group 1 boilers that may be adopted under section 407(b)(2) of the Act. The March 22, 1994 rule states that Group 1, Phase II units must comply with any revised Group 1 emission limitations starting on January 1, 2000. Because EPA has not determined whether to revise the Group 1 emission limitations under section 407(b)(2), it is unnecessary to state, in the rule at this time, the compliance date for such revised limitations. If and when the limitations are revised, the rule will be amended to add both the limitations and the compliance date. Sections 76.5(g) and 76.10(f)(1)(iii) are revised to remove that compliance date.

3. Alternative Emission Limitations

In order to ensure that § 76.10 is consistent with the new definition of the term ''low NO_X burner technology,'' all phrases in the section that elaborated on that term are eliminated. In particular, in §§ 76.10(a)(1) and (2) of the March 22, 1994 rule, the term ''low NO_X burner technology'' is followed by phrases such as: ''including separated overfire air''; ''incorporating both close-coupled and separated overfire air''; or ''incorporating combustion air staging above the top burner level'' (59 FR 13567–13568). The revised rule excludes all of these phrases and is reworded as necessary to reflect their removal. As a result of these changes, units with Group 1 boilers may apply for AELs if they are unable to meet applicable emission limitations using low NO_X burner technology under the new definition in § 72.2.[8]

The revised rule also adds that units with tangentially fired boilers may seek AELs where they cannot meet the applicable emission limitations using separated overfire air. In order to comply with the March 22, 1994 low-NO_X-burner-technology definition, which was then in effect and included close-coupled and separated overfire air, some units installed only separated overfire air. The record information to date indicates that separated overfire air alone is at least as effective in reducing NO_X emissions as low NO_X burner technology as applied to tangentially fired boilers. See Docket Item IV–A–10, Background Document for RIA of NO_X Regulations, appendix A at 21. The Agency therefore maintains that such units should not be disqualified from seeking an AEL because of their efforts to comply with the March 22, 1994 rule. Sections 76.10(a)(1) and (2)(i)(A) are revised to allow such units to seek AELs.

For similar reasons, the definition of ''alternative technology'' set forth in § 76.2 is revised. Under the revised rule, ''alternative technology'' is NO_X emission control technology other than low NO_X burner technology but does not include overfire air for wall-fired boilers and separated overfire air for tangentially fired boilers. Under §§ 76.10(a) and (e)(11), a unit using alternative technology, in addition to or in lieu of low NO_X burner technology, to reduce NO_X emissions must show an annual average emissions reduction of greater than 65 percent in order to qualify for an AEL. The revision of the alternative-technology definition excludes units with tangentially fired boilers applying separated overfire air from the 65-percent reduction requirement.[9] This avoids putting at a disadvantage, for purposes of obtaining AELs, units that may have installed separated overfire air because of the March 22, 1994 low-NO_X-burner-technology definition.

Moreover, certain dates in § 76.10(c)(1), concerning the submission of petitions for an AEL demonstration period, and in § 76.10(f)(1), concerning approved AEL demonstration periods, are changed. See 59 FR 13568 and 13570. These revisions reflect the change in the compliance deadline from January 1, 1995 to January 1, 1996.

Finally, certain provisions, concerning information included in petitions for AEL demonstration periods and for final AELs, in §§ 76.14 and 76.15 of the March 22, 1994 rule refer to combustion air or air flow through ''overfire air ports'' or ''combustion air staging ports.'' Since low NO_X burner technology now excludes air nozzles or ports located outside a waterwall hole that includes a burner, these references are no longer appropriate. The provisions have been modified to apply

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[7] Twenty-five units applied for a 2-year Phase I extension for SO_2 under § 72.42 (which automatically granted them a 2-year NO_X extension), and 6 units applied for a 15 month Phase I NO_X compliance extension under § 76.12.

[8] Since low NO_X burner technology does not include air nozzles or ports located outside of a waterwall hole that includes a burner, provisions in § 76.10 concerning the technical feasibility of installing such air nozzles or ports are irrelevant. Consequently, the March 22, 1994 provisions in §§ 76.10(a)(3) and (d)(4) are entirely eliminated. See 59 FR 13568–13569. The revised rule also reflects the removal of any reference to these eliminated provisions and the renumbering that results from their elimination. See 59 FR 13568–69 and 13574. In addition, the requirement in § 76.10(g)(1)(ii)(C) that the designated representative revise the AEL demonstration period plan is changed to apply only when the owner or operator identifies *operating* modifications (whether for the boiler or the NO_X emission control system) that improve NO_X reductions. Consistent with § 76.10(a)(2)(iii)(B), this does not require revision of the plan to include operating modifications that would prevent the boiler or NO_X control system from being operated in accordance with the bid and design specifications on which the design of the NO_X control system is based. Plan revision is no longer required for all possible equipment modifications or upgrades since they could be outside the new low-NO_X-burner technology definition. See 59 FR 13570–13571.

[9] In order to avoid repeating in other sections the NO_X control technology requirements set forth in § 76.10(a)(2) for qualifying for an AEL (e.g., that a Group 1 boiler install low NO_X burner technology, alternative technology, or, for a tangentially fired boiler, separated overfire air), the references in §§ 76.10(d)(8) and (e)(2)–(4) and 76.15(c) to specific technologies are replaced by a general reference to the ''installed NO_X emission control system'' or ''NO_X emission control system.'' Such a system must, of course, meet the requirements in § 76.10(a)(2). In addition, § 76.10(e)(2) is also revised to make it consistent with § 76.10(d)(8).

only to tangentially fired boilers (which may use close-coupled overfire air) and to refer to the ''distribution of combustion air'' within the ''NO_X emission control system.'' See 59 FR 13574 (§ 76.14(a)(2)(i)) and 13575 (§ 76.15(b)(3) and (d)(2)).[10]

As a result of these changes, the revised rule complies with the Court's decision. The rule provides that, in applying for an AEL, the designated representative for an affected Group 1 unit must demonstrate that the unit cannot meet the presumptive emission limit using properly installed and operated low NO_X burner technology as redefined (or alternative technology or, for tangentially fired boilers, separated overfire air) that is designed to meet the presumptive limit. The designated representative is not required to attempt to meet the presumptive limit using low NO_X burners plus overfire air for wall-fired boilers or separated overfire air for tangentially fired boilers. Rather, in keeping with the Court's decision, the designated representative may base the petition for an AEL on the use of only low NO_X burners. Nothing in the Court's decision mandates any further changes in the AEL provisions.

4. NO_X Averaging Plans

Section 76.11 is revised to change the provisions concerning compliance on an individual basis and on a group basis with the emission limitations in NO_X averaging plans and to clarify language in the formulas implementing the requirements of such plans.

Under § 76.11(d) of the March 22, 1994 rule, units governed by a NO_X averaging plan must comply with both individual-unit limits ''and'', where applicable, a group emission requirement. 59 FR 13572 (§ 76.11(d)(1)(i)(B)). An averaging plan must state individual-unit limits for all units in the plan, i.e., an alternative contemporaneous annual emission limitation and, in most cases, an annual heat input limit. The formula for setting the individual-unit limits is Equation 1 in § 76.11(a)(6). Each unit's actual annual average emission rate must not exceed that unit's alternative contemporaneous annual emission limitation. Further, if the alternative contemporaneous annual emission limitation is less stringent than the applicable emission limitation, the unit's actual annual heat input must not exceed the unit's annual heat input limit. If the alternative contemporaneous annual emission limitation is more stringent, the unit's heat input must not be less than the heat input limit.

The March 22, 1994 rule also provides that if one or more of the units under the plan fail to meet the individual-unit limits, there must be a showing that the entire group of units under the plan complies with a group emission requirement. The group emission requirement is met where the actual Btu-weighted annual average emission rate for the units in the plan does not exceed the Btu-weighted annual average emission rate for these units if they had operated in compliance with the applicable emission limitation in §§ 76.5, 76.6, or 76.7. The formula for determining group compliance is Equation 2 in § 76.11(d)(1)(ii)(A).

Section 76.11(d)(2) of the March 22, 1994 rule addresses liability where units under the NO_X averaging plan fail to meet any of the requirements of the plan, including the individual-unit limits and the group emission requirement. Under § 76.11(d)(2)(i), the owners and operators of each unit under the plan are liable for any violations of the plan (or of § 76.11) by any unit under the plan. Such liability expressly includes the excess emissions penalty under 40 CFR part 77 and section 411 of the Act and penalties under section 113 of the Act. The only exception to the liability provision in § 76.11(d)(2)(i) is that if the group showing of compliance under § 76.11(d)(1)(ii) is made, then no unit under the plan is subject to the excess emissions penalty. Regardless of whether the group showing of compliance (which is for purposes of excess emissions) is made, the March 22, 1994 rule does not exempt any unit under the plan from liability under section 113 for violation of the individual-unit limits.

In contrast with the March 22, 1994 rule, the revised rule provides that if one or more units fail to meet the individual-unit limits but there is a showing of group compliance for the year, then all units in the plan will be deemed to be in compliance for the year with the individual-unit limits. With regard to their NO_X emissions for the year, all units therefore will be in compliance with the averaging plan and have no potential liability for violation of the plan or part 76. Further, none of the units will have excess emissions for the year under part 77.

The Agency has received public comment to the effect that this revised approach, which was proposed in the original November 25, 1992 proposed NO_X rule, is more consistent with the purposes of section 407 than the approach adopted in the March 22, 1994 rule. Neither section 407(e) nor the legislative history specifically address this matter. However, section 407(e) states that individual units' alternative contemporaneous annual emission limitations must ''ensure that the units' actual annual NO_X emission rate'' averaged over the units in question does not exceed the ''Btu-weighted annual average emission rate for the same units'' if they had met the applicable emission limitations under section 407(b). 15 U.S.C 7651f(e). That goal is satisfied where units fail to meet the individual-unit limits in the NO_X averaging plan but can show group compliance with the plan.

Further, even though the March 22, 1994 rule relieves units in such circumstances from liability for excess emissions, the units are still potentially liable for civil penalties, which may be enforceable through Agency action or citizen suits under sections 113 and 304 of the Act. This potential liability is sufficiently significant that a utility with a NO_X averaging plan may, in effect, be forced to comply unit-by-unit with the individual-unit limits even if the group emission requirement could be met without meeting all the individual-unit limits. The individual-unit limits can restrict the utility's flexibility, for example, in dispatching the units in the plan. In order to minimize the likelihood of violating individual-unit limits, some designated representatives have submitted Phase I NO_X averaging plans that set alternative contemporaneous emission limitations equal to the presumptive limits in § 76.5 and that specify no heat input limits. However, under such plans, the individual-unit limits can still restrict the utility's flexibility to choose which units in the plan will be retrofitted with NO_X emission control systems and what types of NO_X emission control systems will be used. The Agency is concerned that the net result of such lack of flexibility is that designated representatives will be encouraged to seek AELs for more units, rather than attempting to average units with higher NO_X emissions with units with lower NO_X emissions. Not only is the case-by-case process of setting AELs administratively burdensome for utilities and the Agency, but also the Agency is concerned that total NO_X emissions are likely to be higher the greater the number of units with AELs.

The Agency concludes that removing the requirement to meet individual-unit limits when there is group compliance

[10] Sections 76.15(a), (b), and (d) are also revised to state, consistent with §§ 76.10(d)(13) and 76.14(a)(2)(v), that the owner or operator ''may'' use for tests and procedures set forth in § 76.15. Further, the language in § 76.15(b)(6) is clarified, and § 76.15(d)(3) is revised to refer more generally to optimization of the combustion process and to cite burner balancing as an example.

under a NO_X averaging plan is a reasonable interpretation of section 407(e) and better implements that provision. Consequently, § 76.11(d)(1)(ii) is revised to state that when the units in a NO_X averaging plan show compliance with the group emission requirement in § 76.11(d)(1)(ii)(A) for a given year, the units will be deemed to comply for that year with their individual emission limitations and heat input limits. Since units meeting group compliance are thereby in compliance with both the individual-unit and group emission requirements of the plan, there is no need to state separately that group compliance relieves the units of any penalties for excess emissions. Section 76.11(d)(2)(ii) is therefore eliminated.[11]

Sections 76.11(a) (6) and (7) and (d)(1)(ii) (A) and (B) are also revised to clarify the formulas (Equations 1 and 2) that govern the selection of individual-unit limits and the showing of group compliance. The language in these sections explaining what ''applicable emission limitation'' to use in Equations 1 and 2 is confusing. The revised rule clarifies that the limitation to be used in Equations 1 and 2 is the applicable emission limitation for each respective unit in §§ 76.5, 76.6, or 76.7. Consistent with that approach, a unit with an AEL must use the applicable emission limitation in §§ 76.5, 76.6, or 76.7 rather than the AEL. The only exception is that an early election unit, which elects to meet NO_X emission limitations in Phase I but is allowed to participate in a NO_X averaging plan only in Phase II, must use the most stringent applicable limitation in §§ 76.5 or 76.7 (i.e., 0.45 lb/mmBtu or 0.50 lb/mmBtu depending on whether the unit's boiler is wall-fired or tangentially fired) or, if the limitation is revised and made more stringent for Phase II under section 407(b)(2), the revised limitation applicable to the boiler type.

In order to simplify the language in §§ 76.11(a)(7) and (d)(1)(ii)(B) in the March 22, 1994 rule, the references to Phase II units are removed. To capture the concept in the March 22, 1994 provisions that Phase II units cannot participate in averaging plans before January 1, 2000, § 76.11(a)(1) is revised to state that a unit in an averaging plan in Phase I must be a Phase I unit with a Group 1 boiler.

EPA notes that it has received public comments concerning the use of a single NO_X averaging plan for units of two or more operating companies (also referred to as utility systems) that are subsidiaries of a single holding company. In such a case, the operating companies would designate the same designated representative (probably someone at the holding company level) for their units in order to meet the common designated representative requirement for a NO_X averaging plan. Each operating company could still designate its own alternate designated representative. Concern was raised that the designated representative at the holding company level may not be readily accessible and that operating companies may need the flexibility of having two persons at the operating company level with authority to act for the designated representative. The Agency is currently reviewing this matter and, in light of the public comments, will propose, in a future rulemaking, revisions to 40 CFR part 72 that would allow designation of a second alternate designated representative for units under certain limited circumstances. Such circumstances could be where: The unit's utility system is a subsidiary of a holding company with two or more utility-system subsidiaries in two or more states; and, in order to use a NO_X averaging plan involving units of two or more such subsidiaries, all the utility-system subsidiaries of that holding company have the same designated representative. EPA intends to consider this revision, and other revisions to streamline part 72, in a rulemaking to be completed in 1995.

5. Phase I NO_X Compliance Extensions

Section 76.12 is revised in order to reflect the new low-NO_X-burner-technology definition. The March 22, 1994 rule provides for a Phase I NO_X compliance extension where a tangentially fired boiler was designed and guaranteed, but failed, to meet the presumptive emission limit and there is a contract to install close-coupled or separated overfire air on or before January 1, 1996. The March 22, 1994 rule includes similar language, with regard to wall-fired boilers, providing a Phase I NO_X compliance extension where there is a contract to install additional equipment, including overfire air. 59 FR 13572 (§ 76.12(a)(1)(ii) and (iii)). The direct final rule eliminates these provisions and a related provision in § 76.12(b)(3). No extensions were requested under these provisions.

The March 22, 1994 rule also provides for a Phase I NO_X compliance extension for units where low NO_X burner technology designed to meet the presumptive emission limits is not in adequate supply for installation and operation by January 1, 1995, consistent with system reliability. Requests for the extensions were due by October 1, 1994. These provisions are not changed in the revised rule. Extension requests for 6 units under this provision were submitted, and the requests either have already been granted or will be acted on consistent with the revised rule after its effective date.

The Agency is aware that, in very limited circumstances, an additional extension of the compliance date for Phase I NO_X emission limitations may be warranted. These circumstances are as follows: A source has 3 or more units that have extensions under section 404(d) until January 1, 1997 to comply with Phase I NO_X emission limits and, due to claimed operational problems associated with the planned NO_X emission control systems, one unit may need an additional extension to redesign and install low NO_X burner technology. Because of its extension under section 404(d), the unit has not yet installed the NO_X control system that was designed to comply with the low-NO_X-burner technology definition in the March 22, 1994 rule. With the change adopted today in the definition, the unit has flexibility to redesign the NO_X control system to meet the new definition and avoid the claimed operational problems. However, unless an additional compliance extension is granted, there will be insufficient time to install redesigned low NO_X burner technology without causing system reliability problems.

Because the need for an additional extension appears to result from the change in the low-NO_X-burner-technology definition, the Agency maintains that an additional extension may be appropriate in these limited circumstances. In order to provide the designated representative of the unit an opportunity to demonstrate the need for such extension, the revised rule (in § 76.12(e)) requires the submission of a petition for the extension within 15 days of the publication of the revised rule and establishes procedures for acting on the petition. The procedures and the provisions in the revised rule concerning treatment of the unit upon approval of the petition are essentially the same as the procedures and provisions applicable to Phase I NO_X compliance extensions. See 59 FR 13572–13573 (§ 76.12(c) and (d)).

6. Miscellaneous

The revised rule excludes § 76.9(e) of the March 22, 1994 rule, which provides that each ton of excess emissions of

[11] Consistent with these changes, § 76.11(d)(1)(i)(B) is revised to state that units must meet either the individual-unit limits ''or'' the group emission requirement.

NO_X will be a separate violation. In response to the utilities' challenge of § 76.9(e), EPA moved before the Court for a voluntary remand of the provision. The Court granted the motion and therefore EPA is now deleting the provision.

The revised rule also changes provisions concerning the types of units for which reports of cost data on low NO_X burner technology installations must be prepared and the date by which the reports must be submitted under § 76.14(c). Consistent with the new low-NO_X-burner-technology definition, the cost reports are not required for: wall-fired boilers using only overfire air and not low NO_X burners; and tangentially fired boilers using only separated overfire air and not low NO_X burner technology. Because such boilers are not using low NO_X burner technology, cost data on their NO_X emissions controls are not relevant to setting of Group 2, Phase II NO_X emission limitations under section 407(b)(2) of the Act. An analogous change is made in section 1 of appendix B to part 76.

Also excluded from cost reporting are units that begin installing a new NO_X emission control system after 120 days from publication of the instant direct final rule in the Federal Register. In light of the statutory requirement that Group 2, Phase II emission limitations be established by January 1, 1997, the Agency maintains that cost information on those units would be received too late to be useful in the rulemaking on such emission limitations.

Finally, the date for submission of cost reports is revised in § 76.14(c)(3) to take account of the vacating of the March 22, 1994 rule by the Court. As in the March 22, 1994 rule, the cost reports must be submitted within 120 days after completion of the low NO_X burner technology retrofit project. However, in order to provide time for resumption and completion of cost data collection that may have been stopped when the rule was vacated, the revised rule ensures that all projects will have at least 40 days, from the publication of the revised rule in the Federal Register, to submit the cost reports. Cost reports on projects completed more than 80 days before publication of the direct final rule must be submitted by the 40th day after such publication.

B. Reissuance of the Emission Limits

Section 407(b)(1) requires the Administrator to adopt by regulation the presumptive emission limits unless she finds that they cannot be achieved using low NO_X burner technology. In the March 22, 1994 rule, the Administrator found that the record evidence showed that the presumptive limits were achievable using low NO_X burners plus overfire air for wall-fired boilers and separated overfire air for tangentially fired boilers (59 FR 13546). In light of the revised low-NO_X-burner-technology definition, the Administrator has reviewed the record concerning the performance of low NO_X burners and concludes that the presumptive limits are still achievable. The revised rule therefore reissues the presumptive limits of 0.50 lb/mmBtu for wall-fired boilers and 0.45 lb/mmBtu for tangentially fired boilers.

The record includes analyses conducted by DOE in which the presumptive limits were examined in light of the low-NO_X-burner-technology definition supported by DOE, i.e., the third approach in the November 25, 1992 proposal. The revised rule adopts in essence the same definition as DOE supported. As discussed below, DOE concluded, and the utilities agreed, that most units could achieve the presumptive limits using low NO_X burners without overfire air for wall-fired boilers and without separated overfire air for tangentially fired boilers. See, *e.g.*, Docket Item IV–D–162, Fourth Supplementary Comments of UARG, February 2, 1994 at 16–23.

After reviewing a number of sources of information on control technology efficiency, DOE estimated control technology performance based primarily on data from ongoing demonstration projects and other recent installations of NO_X control systems. The analysis of data from wall-fired and tangentially fired boilers, fitted with low NO_X burner technology as defined by DOE, indicated that NO_X reductions of 45 to 50 percent would be achieved at wall-fired boilers and of 35 to 37 percent would be achieved at tangentially fired boilers (57 FR 55646–55647). DOE's NO_X control technology performance estimates were consistent with average NO_X reductions projected by the utilities. The utilities projected average NO_X reductions of 47 percent with use of burner retrofits for wall-fired boilers and 35 to 37 percent with the use of LNCFS 1 for tangentially fired boilers (Docket Item IV–D–111 at 59–61).[12] Further, the utilities supported DOE's performance estimates in their brief to the Court in *Alabama Power* (Docket Item VIII–A–1, Brief of Petitioners, July 1, 1994, at 18–19).

DOE's analysis also showed that, assuming 45 percent control efficiency for wall-fired boilers and 35 percent for tangentially fired boilers, less than 10 percent of the Group 1 units would fail to meet the presumptive limits (57 FR 55648). Further, the utilities similarly concluded that ''review of the uncontrolled emissions at wall-fired and tangentially fired boilers, and of the capabilities of low NO_X burner technology, show that (the presumptive) limits are aggressive but generally achievable by most Group 1 units with the use of (low NO_X burners) alone'' (Docket Item IV–D–111 at 138). The utilities reiterated this conclusion before the Court in *Alabama Power.* The utilities stated that ''all of the tangentially fired boiler groupings analyzed by EPA's contractor would comply with the final presumptive emission limitation using low NO_X burners alone for tangentially fired boilers (i.e., LNCFS 1), without the use of separated overfire air'' (Docket Item VIII–A–1, Brief of Petitioners at 40).

In the March 22, 1994 preamble, EPA did not adopt DOE's analysis and instead presented its own analysis of control technology performance data available after promulgation of the November 25, 1992 proposal. The EPA found that the majority of wall-fired boilers would be expected to achieve NO_X reductions of 40 to 50 percent using low NO_X burners only and no overfire air (59 FR 13546). The EPA also found that tangentially fired boilers using LNCFS 1 would achieve reduction of 20 to 25 percent. While EPA's finding on wall-fired boilers is consistent with DOE's finding, the two analyses differ concerning tangentially fired boilers. However, upon reconsideration, the Agency finds that the 20 to 25 percent estimate of reductions achievable using LNCFS 1 erroneously excluded the reductions using a form of LNCFS 1 referred to in the March 22, 1994 preamble as ''LNCFS 1+.'' 59 FR 13546–13547. Because ''LNCFS 1+'' (i.e., Lansing Smith Unit 2)[13] employs the

[12] Since the completion of DOE's analysis, other types of low NO_X burner technology have been developed for tangentially fired boilers. See footnote 3 above. Although EPA currently lacks data on the long-term performance of these NO_X controls, the outlook for their performance is promising.

[13] DOE's analysis included Fiddler's Ferry Unit 1 as a unit with LNCFS 1. Since installation of LNCFS 1 in that unit involved major modifications of the existing waterwall holes (i.e., cutting out a waterwall section having a height of 3 feet above each existing waterwall hole and a width equal to the width of the hole), the unit's NO_X control system does not fall within the new low-NO_X-burner technology definition, which includes minor modifications of the existing hole. See Docket Item II–E–11, Record of Telephone Conversations, October 12, 1992. However, eliminating the emission reduction results of that unit does not change the conclusion that LNCFS 1 (e.g., at Lansing Smith Unit 2) can achieve 35 to 37 percent reductions.

same hardware (i.e., air nozzles in the hole with the burner) as LNCFS 1 applications, there is no basis of distinguishing ''LNCFS 1+''. The differences between EPA's and DOE's data are eliminated by treating ''LNCFS 1+'' as included in LNCFS 1 and considering the performance results of ''LNCFS 1+'' as included in results for LNCFS 1.

Upon reconsideration, EPA concurs with the aforementioned DOE and utilities' analyses. EPA, therefore, retains in the revised rule the presumptive limits for Group 1 boilers.

C. Permit Status

Pursuant to the March 22, 1994 rule, the designated representatives of Phase I units with wall-fired or tangentially-fired boilers submitted NO_X compliance plans. (See 59 FR 13567 (§ 76.9 (a) through (c))). For units lacking Acid Rain permits, the NO_X compliance plans were submitted along with applications for such permits. For units that already had Acid Rain permits covering SO_2 emission limitations, the NO_X compliance plans were submitted as permit revisions. Most of the plans required NO_X compliance commencing on January 1, 1995. Twenty-five units had previously been granted 2-year extensions for NO_X compliance under § 72.42, and designated representatives for 6 more units requested 15-month extensions under § 76.12 of the March 22, 1994 rule.

The Agency followed the applicable permit issuance and revision procedures under part 72 of the Acid Rain permits rule. These procedures required notice of a proposed permit or proposed permit revision and opportunity for public comment prior to issuance of a final permit or final revised permit. Most of the submitted NO_X compliance plans were already approved and included in final permits or final revised permits before the November 29, 1994 *Alabama Power* decision vacating the March 22, 1994 rule. Because of the vacating of the rule, the Agency has deferred action on those plans and extension requests that were not yet approved when the Court issued its decision.

Under the March 22, 1994 rule, NO_X compliance plans had to identify which one of several possible compliance options was proposed for each Phase I unit with a Group 1 boiler. *Id.* (§ 76.9(c)(4)). In the NO_X compliance plans already submitted to the Agency, units sought to comply either with the presumptive limits or through NO_X emissions averaging plans. The units that requested NO_X compliance extensions sought to comply either with the presumptive limits or through NO_X emissions averaging plans after the extensions expire.

If, as anticipated, the revised rule becomes final and thereby reinstates the NO_X emission reduction program, the Agency sees no need for utilities to resubmit and for EPA to reissue, through notice and comment procedures, the NO_X compliance plans that have already been approved and issued in final form in permits or permit revisions. The final permits and permit revisions set forth the applicable NO_X emission limitations and do not state any definition for low NO_X burner technology. The revised rule changes the low-NO_X-burner-technology definition but does not change the presumptive limits or the formulas for setting individual-unit limits or showing group compliance in averaging plans. The revised rule preserves without change the provisions governing the Phase I extensions that were requested and either were approved or that would have been approved under the March 22, 1994 rule. The revised rule also does not change the application requirements in § 76.9 or the permit issuance or permit revision procedures in parts 72 and 76 applicable to NO_X compliance plans.

The only changes that the revised rule makes in the submitted NO_X compliance plans are in the general compliance date and in the effect of group compliance on individual-unit limits in NO_X averaging plans. The general deadline for compliance by a Group 1, Phase I unit with NO_X emission limitations is now the later of January 1, 1996 (rather than 1995) or the date on which a unit is subject to SO_2 emission reduction requirements under section 404(d) of the Act. The revised rule also mandates, for all NO_X averaging plans, that where the units in an averaging plan show they meet the group compliance requirement, the units are deemed to meet their individual-unit limits. All NO_X compliance plans must conform to the revised rule.

As discussed above, the Agency has issued, elsewhere in this Federal Register, a notice of proposal requesting comments on the provisions of the revised rule. Any comments concerning the compliance deadline and the group compliance provisions should be made in response to that notice and would not be appropriate in the context of permit issuance. All other aspects of the submitted NO_X compliance plans have already been subject to notice and comment and are unchanged by the revised rule.

The Agency concludes that, once the revised rule becomes final as anticipated, conforming changes in the compliance date and group compliance provisions in otherwise unchanged NO_X compliance plans are properly considered administrative amendments under § 72.83 of the Acid Rain permits rule because there is no basis for requiring notice and comment on the changes. All existing permits that include NO_X compliance plans will be amended under § 72.83 to the extent necessary to make them consistent with the new compliance date and group compliance requirements. The administrative amendments will reinstate the NO_X compliance plans as amended and the approved Phase I NO_X compliance extensions under §§ 72.42 and 76.12 that are referenced in the plans.

With regard to NO_X compliance plans in permits or permit revisions issued in draft form for public comment but not yet issued in final form, the Agency will complete the issuance procedure in accordance with the revised rule once the rule becomes final. Since, except for the compliance date and group compliance provisions, neither the substance of such plans nor the issuance procedures were changed by the revised rule, there is no need to reopen the public comment period on the plans.

Any plans that have not yet been issued in draft form will also be processed by the Agency in accordance with the revised rule and part 72. Similarly, any Phase I NO_X compliance extensions requested under § 76.12 and not acted on before November 29, 1994 will be acted on consistent with the revised rule. It should be noted that, if significant, adverse comment is timely received on relevant portions of the instant direct final rule, the NO_X compliance plans could be subject to further change depending on the outcome of the rulemaking initiated by the notice of proposed rule issued elsewhere in this Federal Register.

IV. Administrative Requirements

A. 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 $276 million starting in 2000. 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.

EPA does not believe a revised Regulatory Impact Analysis (RIA) is needed for the direct final rule, which, in large part, reinstates the March 22, 1994 rule and which imposes no new costs beyond what costs were estimated in the RIA to the March 22, 1994 rule. The EPA does not anticipate major increases in prices, costs, or other significant adverse effects on competition, investment, productivity, or innovation or on the ability of U.S. enterprises to compete with foreign enterprises in domestic or foreign markets due to the final rule.

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 rule 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 NO_X requirements are fully implemented in the year 2000, consumer electric utility rates are expected to rise by 0.12 percent on average due to this rulemaking. Consequently, the rule is not likely to have an impact on utility profits or competitiveness.

B. Unfunded Mandates Act

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

Under section 205 of the Unfunded Mandates Act, the Agency must identify and consider a reasonable number of regulatory alternatives before promulating a rule for which a budgetary impact statement must be prepared. The Agency must select from those alternatives the least costly, most cost-effective, or least burdensome alternative, for State, local, and tribal governments and the private sector, 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.

Because this direct final rule is estimated to result in the expenditure by State, local, and tribal governments, in aggregate, or the private sector of over $100 million per year starting in 2000, EPA has prepared a supplement to the Regulatory Impact Statement in compliance with the Unfunded Mandates Act. EPA summarizes that supplement as follows.

The direct final rule is promulgated under section 407 of the Clean Air Act. The rule is issued in response to a remand by the U.S. Court of Appeals for the District of Columbia Circuit and, in large part, reinstates the remanded March 22, 1994 rule. Thus, the analysis in the RIA developed in preparation of the March 22, 1994 rule was appropriately considered in response to the requirements of the Unfunded Mandates Act.

Total expenditures resulting from the direct final rule are estimated at: $69 million (of which less than $1 million is by State, local, and tribal governments) per year in 1995–1999; and $276 million (of which $21 million is by State, local, and tribal governments) per year starting in 2000. There are no federal funds available to assist State, local, and tribal governments in meeting these costs. There are important benefits from NO_X emission reductions because atmospheric emissions of NO_X have significant, adverse impacts on human health and welfare and on the environment.

The 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. On the contrary, 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.

Prior to issuing the March 22, 1994 rule, EPA provided numerous opportunities, e.g., through the Acid Rain Advisory Committee proceedings, the public comment period, and public hearings, for consultation with interested parties, including State, local, and tribal governments. In general, State and local environmental agencies advocated that EPA adopt more stringent environmental controls while municipally-owned utilities advocated less stringent controls and more compliance flexibility. EPA evaluated the comments and concerns expressed, and the direct final rule reflects, to the extent consistent with section 407 of the Clean Air Act, those comments and concerns. While small governments are not significantly or uniquely affected by the rule, these procedures, as well as additional public conferences and meetings, gave small governments an opportunity to give meaningful and timely input and obtain information, education, and advice on compliance.

The Agency considered several regulatory options in developing the rule. The option selected in the direct final rule is the least costly and least burdensome alternative currently available for achieving the objectives of section 407. The Agency rejected another alternative that was the most cost-effective alternative because the U.S. Court of Appeals for the D.C. Circuit held that the latter alternative was beyond the Agency's statutory authority.

C. Paperwork Reduction Act

The OMB has approved the information collection requirements contained in this rule under the provisions of the Paperwork Reduction Act of 1980, 44 U.S.C. 3501, *et seq.*, and has assigned OMB control number 2060–0258.

Public reporting burden for this collection of information is estimated at 27,510 hours for all respondents through May 15, 1995. This estimate includes time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

The Agency notes that this burden estimate was originally developed based on the March 22, 1994 rule. Today's direct final rule includes revisions to cost reporting requirements in the March 22, 1994 rule that result in a small reduction in overall burden. In order to account for this small reduction, the Agency will submit an adjustment to the current Information Collection Report.

Send comments regarding this change in the information collection requirements or any other aspect of this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch (PM–223Y), U.S. Environmental Protection Agency, 401 M Street SW., Washington, DC 20460; and to the Paperwork Reduction Project, Office of Information and Regulatory Affairs, Office of Management and Budget, 726 Jackson Place NW., Washington, DC 20503, marked ''Attention: Desk Officer for EPA.''

D. Regulatory Flexibility Act

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

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

Under the Regulatory Flexibility Act, a small business is any ''small business concern'' as identified by the Small Business Administration under section 3 of the Small Business Act. As of January 1, 1991, the Small Business Administration had established the size threshold for small electric services companies at 4 million megawatt hours per year. Because all of the utilities affected by Phase I of the Acid Rain regulations have generating capacities greater than 4 million megawatt hours, EPA believes that no small businesses are affected by today's revised rule. The EPA's initial estimates are that the burden on small utilities under Phase II is minimal.

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

E. 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

Acid rain program, Air pollution control, Nitrogen oxide, Incorporation by reference, Reporting and recordkeeping requirements.

Dated: March 31, 1995.

Carol M. Browner,

Administrator.

Title 40, chapter I, of the Code of Federal Regulations is amended as follows:

1. Part 76 is revised to read as follows:

PART 76—ACID RAIN NITROGEN OXIDES EMISSION REDUCTION PROGRAM

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

§ 76.1 Applicability.

(a) Except as provided in paragraphs (b) through (d) of this section, the provisions apply to each coal-fired utility unit that is subject to an Acid Rain emissions limitation or reduction requirement for SO_2 under Phase I or Phase II pursuant to sections 404, 405, or 409 of the Act.

(b) The emission limitations for NO_X under this part apply to each affected coal-fired utility unit subject to section 404(d) or 409(b) of the Act on the date the unit is required to meet the Acid Rain emissions reduction requirement for SO_2.

(c) The provisions of this part apply to each coal-fired substitution unit or compensating unit, designated and approved as a Phase I unit pursuant to §§ 72.41 or 72.43 of this chapter as follows:

(1) A coal-fired substitution unit that is designated in a substitution plan that is approved and active as of January 1, 1995 shall be treated as a Phase I coal-fired utility unit for purposes of this part. In the event the designation of such unit as a substitution unit is terminated after December 31, 1995, pursuant to § 72.41 of this chapter and the unit is no longer required to meet Phase I SO_2 emissions limitations, the provisions of this part (including those applicable in Phase I) will continue to apply.

(2) A coal-fired substitution unit that is designated in a substitution plan that is not approved or not active as of January 1, 1995, or a coal-fired compensating unit, shall be treated as a Phase II coal-fired utility unit for purposes of this part.

(d) The provisions of this part for Phase I units apply to each coal-fired transfer unit governed by a Phase I extension plan, approved pursuant to

§ 72.42 of this chapter, on January 1, 1997. Notwithstanding the preceding sentence, a coal-fired transfer unit shall be subject to the Acid Rain emissions limitations for nitrogen oxides beginning on January 1, 1996 if, for that year, a transfer unit is allocated fewer Phase I extension reserve allowances than the maximum amount that the designated representative could have requested in accordance with § 72.42(c)(5) of this chapter (as adjusted under § 72.42(d) of this chapter) unless the transfer unit is the last unit allocated Phase I extension reserve allowances under the plan.

§ 76.2 Definitions.

All terms used in this part shall have the meaning set forth in the Act, in § 72.2 of this chapter, and in this section as follows:

Alternative contemporaneous annual emission limitation means the maximum allowable NO_X emission rate (on a lb/mmBtu, annual average basis) assigned to an individual unit in a NO_X emissions averaging plan pursuant to § 76.10.

Alternative technology means a control technology for reducing NO_X emissions that is outside the scope of the definition of low NO_X burner technology. Alternative technology does not include overfire air as applied to wall-fired boilers or separated overfire air as applied to tangentially fired boilers.

Approved clean coal technology demonstration project means a project using funds appropriated under the Department of Energy's "Clean Coal Technology Demonstration Program," up to a total amount of $2,500,000,000 for commercial demonstration of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency. The Federal contribution for a qualifying project shall be at least 20 percent of the total cost of the demonstration project.

Cell burner boiler means a wall-fired boiler that utilizes two or three circular burners combined into a single vertically oriented assembly that results in a compact, intense flame. Any low NO_X retrofit of a cell burner boiler that reuses the existing cell burner, close-coupled wall opening configuration would not change the designation of the unit as a cell burner boiler.

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, for Phase I units in calendar year 1990 and, for Phase II units in the calendar year 1995. For the purposes of this part, this definition shall apply notwithstanding the definition at § 72.2 of this chapter.

Cyclone boiler means a boiler with one or more water-cooled horizontal cylindrical chambers in which coal combustion takes place. The horizontal cylindrical chamber(s) is (are) attached to the bottom of the furnace. One or more cylindrical chambers are arranged either on one furnace wall or on two opposed furnace walls. Gaseous combustion products exiting from the chamber(s) turn 90 degrees to go up through the boiler while coal ash exits the bottom of the boiler as a molten slag.

Demonstration period means a period of time not less than 15 months, approved under § 76.10, for demonstrating that the affected unit cannot meet the applicable emission limitation under §§ 76.5, 76.6, or 76.7 and establishing the minimum NO_X emission rate that the unit can achieve during long-term load dispatch operation.

Dry bottom means the boiler has a furnace bottom temperature below the ash melting point and the bottom ash is removed as a solid.

Economizer means the lowest temperature heat exchange section of a utility boiler where boiler feed water is heated by the flue gas.

Flue gas means the combustion products arising from the combustion of fossil fuel in a utility boiler.

Group 1 boiler means a tangentially fired boiler or a dry bottom wall-fired boiler (other than a unit applying cell burner technology).

Group 2 boiler means a wet bottom wall-fired boiler, a cyclone boiler, a boiler applying cell burner technology, a vertically fired boiler, an arch-fired boiler, or any other type of utility boiler (such as a fluidized bed or stoker boiler) that is not a Group 1 boiler.

Low NO_X burners and *low NO_X burner technology* means commercially available combustion modification NO_X controls that minimize NO_X formation by introducing coal and its associated combustion air into a boiler such that initial combustion occurs in a manner that promotes rapid coal devolatilization in a fuel-rich (i.e., oxygen deficient) environment and introduces additional air to achieve a final fuel-lean (i.e., oxygen rich) environment to complete the combustion process. This definition shall include the staging of any portion of the combustion air using air nozzles or registers located inside any waterwall hole that includes a burner. This definition shall exclude the staging of any portion of the combustion air using air nozzles or ports located outside any waterwall hole that includes a burner (commonly referred to as NO_X ports or separated overfire air ports).

Operating period means a period of time of not less than three consecutive months and that occurs not more than one month prior to applying for an alternative emission limitation demonstration period under § 76.10, during which the owner or operator of an affected unit that cannot meet the applicable emission limitation:

(1) Operates the installed NO_X emission controls in accordance with primary vendor specifications and procedures, with the unit operating under normal conditions; and

(2) records and reports quality-assured continuous emission monitoring (CEM) and unit operating data according to the methods and procedures in part 75 of this chapter.

Primary vendor means the vendor of the NO_X emission control system who has primary responsibility for providing the equipment, service, and technical expertise necessary for detailed design, installation, and operation of the controls, including process data, mechanical drawings, operating manuals, or any combination thereof.

Reburning means reducing the coal and combustion air to the main burners and injecting a reburn fuel (such as gas or oil) to create a fuel-rich secondary combustion zone above the main burner zone and final combustion air to create a fuel-lean burnout zone. The formation of NO_X is inhibited in the main burner zone due to the reduced combustion intensity, and NO_X is destroyed in the fuel-rich secondary combustion zone by conversion to molecular nitrogen.

Selective catalytic reduction means a noncombustion control technology that destroys NO_X by injecting a reducing agent (e.g., ammonia) into the flue gas that, in the presence of a catalyst (e.g., vanadium, titanium, or zeolite), converts NO_X into molecular nitrogen and water.

Selective noncatalytic reduction means a noncombustion control technology that destroys NO_X by injecting a reducing agent (e.g., ammonia, urea, or cyanuric acid) into the flue gas, downstream of the combustion zone that converts NO_X to molecular nitrogen, water, and when urea or cyanuric acid are used, to carbon dioxide (CO_2).

Stoker boiler means a boiler that burns solid fuel in a bed, on a stationary or moving grate, that is located at the bottom of the furnace.

Tangentially fired boiler means a boiler that has coal and air nozzles mounted in each corner of the furnace where the vertical furnace walls meet. Both pulverized coal and air are directed from the furnace corners along a line tangential to a circle lying in a horizontal plane of the furnace.

Turbo-fired boiler means a pulverized coal, wall-fired boiler with burners arranged on walls so that the individual flames extend down toward the furnace bottom and then turn back up through the center of the furnace.

Wall-fired boiler means a boiler that has pulverized coal burners arranged on the walls of the furnace. The burners have discrete, individual flames that extend perpendicularly into the furnace area.

Wet bottom means the boiler has a furnace bottom temperature above the ash melting point and the bottom ash is removed as a liquid.

§ 76.3 General Acid Rain Program provisions.

The following provisions of part 72 of this chapter shall apply to this part:

(a) § 72.2 (Definitions);

(b) § 72.3 (Measurements, abbreviations, and acronyms);

(c) § 72.4 (Federal authority);

(d) § 72.5 (State authority);

(e) § 72.6 (Applicability);

(f) § 72.7 (New unit exemption);

(g) § 72.8 (Retired units exemption);

(h) § 72.9 (Standard requirements);

(i) § 72.10 (Availability of information); and

(j) § 72.11 (Computation of time).

In addition, the procedures for appeals of decisions of the Administrator under this part are contained in part 78 of this chapter.

§ 76.4 Incorporation by reference.

(a) The materials listed in this section are incorporated by reference in the sections noted. These incorporations by reference (IBR's) were approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. These materials are incorporated as they existed on the date of approval, and notice of any change in these materials will be published in the Federal Register. The materials are available for purchase at the corresponding address noted below and are available for inspection at the Office of the Federal Register, 800 North Capitol St., NW., 7th Floor, Suite 700, Washington, DC, at the Public Information Reference Unit, U.S. EPA, 401 M Street, SW., Washington, DC, and at the Library (MD–35), U.S. EPA, Research Triangle Park, North Carolina.

(b) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Materials (ASTM), 1916 Race Street, Philadelphia, Pennsylvania 19103; or the University Microfilms International, 300 North Zeeb Road, Ann Arbor, Michigan 48106.

(1) ASTM D 3176–89, Standard Practice for Ultimate Analysis of Coal and Coke, IBR approved May 23, 1995 for § 76.15.

(2) ASTM D 3172–89, Standard Practice for Proximate Analysis of Coal and Coke, IBR approved May 23, 1995 for § 76.15.

(c) The following material is available for purchase from the American Society of Mechanical Engineers (ASME), 22 Law Drive, Box 2350, Fairfield, NJ 07007–2350.

(1) ASME Performance Test Code 4.2 (1991), Test Code for Coal Pulverizers, IBR approved May 23, 1995 for § 76.15.

(2) [Reserved]

(d) The following material is available for purchase from the American National Standards Institute, 11 West 42nd Street, New York, NY 10036 or from the International Organization for Standardization (ISO), Case Postale 56, CH–1211 Geneve 20, Switzerland.

(1) ISO 9931 (December, 1991) ''Coal—Sampling of Pulverized Coal Conveyed by Gases in Direct Fired Coal Systems,'' IBR approved May 23, 1995 for § 76.15.

(2) [Reserved]

§ 76.5 NO_X emission limitations for Group 1 boilers.

(a) Beginning January 1, 1996, or for a unit subject to section 404(d) 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 Phase I coal-fired utility unit with a tangentially fired boiler or a dry bottom wall-fired boiler (other than units applying cell burner technology) 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 paragraphs (c) or (e) of this section or in §§ 76.10, 76.11, or 76.12:

(1) 0.45 lb/mmBtu of heat input on an annual average basis for tangentially fired boilers.

(2) 0.50 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.

(c) Unless the unit meets the early election requirement of § 76.8, the owner or operator of a coal-fired substitution unit with a tangentially fired boiler or a dry bottom wall-fired boiler (other than units applying cell burner technology) that satisfies the requirements of § 76.1(c)(2), shall comply with the NO_X emission limitations that apply to Group 1, Phase II boilers.

(d) The owner or operator of a Phase I unit with a cell burner boiler that converts to a conventional wall-fired boiler on or before January 1, 1995 or, for a unit subject to section 404(d) of the Act, the date the unit is required to meet Acid Rain emissions reduction requirements for SO_2 shall comply, by such respective date or January 1, 1996, whichever is later, with the NO_X emissions limitation applicable to dry bottom wall-fired boilers under paragraph (a) of this section, except as provided in paragraphs (c) or (e) of this section or in §§ 76.10, 76.11, or 76.12.

(e) The owner or operator of a Phase I unit with a Group 1 boiler that converts to a fluidized bed or other type of utility boiler not included in Group 1 boilers on or before January 1, 1995 or, for a unit subject to section 404(d) of the Act, the date the unit is required to meet Acid Rain emissions reduction requirements for SO_2 is exempt from the NO_X emissions limitations specified in paragraph (a) of this section, but shall comply with the NO_X emission limitations for Group 2 boilers under § 76.6.

(f) Except as provided in § 76.8 and in paragraph (c) of this section, each unit subject to the requirements of this section is not subject to the requirements of § 76.7.

(g) 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 wall-fired boiler shall be subject to the emission limitations in paragraph (a) of this section.

§ 76.6 NO_X emission limitations for Group 2 boilers. [Reserved]

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

§ 76.8 Early election for Group 1, Phase II boilers.

(a) *General provisions.* (1) The owner or operator of a Phase II coal-fired utility unit with a Group 1 boiler may elect to have the unit become subject to the applicable emissions limitation for NO_X under § 76.5, starting no later than January 1, 1997.

(2) The owner or operator of a Phase II coal-fired utility unit with a Group 1 boiler that elects to become subject to the applicable emission limitation under § 76.5 shall not be subject to any revised NO_X emissions limitation for Group 1 boilers that the Administrator may issue pursuant to section 407(b)(2) of the Act until January 1, 2008,

provided the designated representative demonstrates that the unit is in compliance with the limitation under § 76.5, using the methods and procedures specified in part 75 of this chapter, for the period beginning January 1 of the year in which the early election takes effect (but not later than January 1, 1997) and ending December 31, 2007.

(3) The owner or operator of any Phase II unit with a cell burner boiler that converts to conventional burner technology may elect to become subject to the applicable emissions limitation under § 76.5 for dry bottom wall-fired boilers, provided the owner or operator complies with the provisions in paragraph (a)(2) of this section.

(4) The owner or operator of a Phase II unit approved for early election shall not submit an application for an alternative emissions limitation demonstration period under § 76.10 until the earlier of:

(i) January 1, 2008; or

(ii) Early election is terminated pursuant to paragraph (e)(3) of this section.

(5) The owner or operator of a Phase II unit approved for early election may not incorporate the unit into an averaging plan prior to January 1, 2000. On or after January 1, 2000, for purposes of the averaging plan, the early election unit will be treated as subject to the applicable emissions limitation for NO_X for Phase II units with Group 1 boilers under §§ 76.5(g) and if revised emission limitations are issued for Group 1 boilers pursuant to section 407(b)(2) of the Act, § 76.7.

(b) *Submission requirements.* In order to obtain early election status, the designated representative of a Phase II unit with a Group 1 boiler shall submit an early election plan to the Administrator by January 1 of the year the early election is to take effect, but not later than January 1, 1997. Notwithstanding § 72.40 of this chapter, and unless the unit is a substitution unit under § 72.41 of this chapter or a compensating unit under § 72.43 of this chapter, a complete compliance plan covering the unit shall not include the provisions for SO_2 emissions under § 72.40(a)(1) of this chapter.

(c) *Contents of an early election plan.* A complete early election plan shall include the following elements in a format prescribed by the Administrator:

(1) A request for early election;

(2) The first year for which early election is to take effect, but not later than 1997; and

(3) The special provisions under paragraph (e) of this section.

(d)(1) *Permitting authority's action.* To the extent the Administrator determines that an early election plan complies with the requirements of this section, the Administrator will approve the plan and:

(i) If a Phase I Acid Rain permit governing the source at which the unit is located has been issued, will revise the permit in accordance with the permit modification procedures in § 72.81 of this chapter to include the early election plan; or

(ii) If a Phase I Acid Rain permit governing the source at which the unit is located has not been issued, will issue a Phase I Acid Rain permit effective from January 1, 1995 through December 31, 1999, that will include the early election plan and a complete compliance plan under § 72.40(a) of this chapter and paragraph (b) of this section. If the early election plan is not effective until after January 1, 1995, the permit will not contain any NO_X emissions limitations until the effective date of the plan.

(2) Beginning January 1, 2000, the permitting authority will approve any early election plan previously approved by the Administrator during Phase I, unless the plan is terminated pursuant to paragraph (e)(3) of this section.

(e) *Special provisions*—(1) *Emissions limitations.*—(i) *Sulfur dioxide.* Notwithstanding § 72.9 of this chapter, a unit that is governed by an approved early election plan and that is not a substitution unit under § 72.41 of this chapter or a compensating unit under § 72.43 of this chapter shall not be subject to the following standard requirements under § 72.9 of this chapter for Phase I:

(A) The permit requirements under §§ 72.9(a)(1) (i) and (ii) of this chapter;

(B) The sulfur dioxide requirements under § 72.9(c) of this chapter; and

(C) The excess emissions requirements under § 72.9(e)(1) of this chapter.

(ii) *Nitrogen oxides.* A unit that is governed by an approved early election plan shall be subject to an emissions limitation for NO_X as provided under paragraph (a)(2) of this section except as provided under paragraph (e)(3)(iii) of this section.

(2) *Liability.* The owners and operators of any unit governed by an approved early election plan shall be liable for any violation of the plan or this section at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in part 77 of this chapter.

(3) *Termination.* An approved early election plan shall be in effect only until the earlier of January 1, 2008 or January 1 of the calendar year for which a termination of the plan takes effect.

(i) If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under § 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year after the year for which there is a failure to demonstrate compliance, and the designated representative may not submit a new early election plan.

(ii) The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated representative must submit a notice under § 72.40(d) of this chapter by January 1 of the year for which the termination is to take effect.

(iii)(A) If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO_X for Phase II units with Group 1 boilers under § 76.5(g) and, if revised emission limitations are issued pursuant to section 407(b)(2) of the Act, § 76.7.

(B) If an early election plan is terminated in or after 2000, the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO_X for Phase II units with Group 1 boilers under § 76.5(g) and, if revised emission limitations are issued pursuant to section 407(b)(2) of the Act, § 76.7.

§ 76.9 Permit application and compliance plans.

(a) *Duty to apply.* (1) The designated representative of any source with an affected unit subject to this part shall submit, by the applicable deadline under paragraph (b) of this section, a complete Acid Rain permit application (or, if the unit is covered by an Acid Rain permit, a complete permit revision) that includes a complete compliance plan for NO_X emissions covering the unit.

(2) The original and three copies of the permit application and compliance plan for NO_X emissions for Phase I shall be submitted to the EPA regional office for the region where the applicable source is located. The original and three copies of the permit application and compliance plan for NO_X emissions for

Phase II shall be submitted to the permitting authority.

(b) *Deadlines.* (1) For a Phase I unit with a Group 1 boiler, the designated representative shall submit a complete permit application and compliance plan for NO_X covering the unit during Phase I to the applicable permitting authority not later than May 6, 1994.

(2) For a Phase I or Phase II unit with a Group 2 boiler or a Phase II unit with a Group 1 boiler, the designated representative shall submit a complete permit application and compliance plan for NO_X emissions covering the unit in Phase II to the Administrator not later than January 1, 1998, except that early election units shall also submit an application not later than January 1, 1997.

(c) *Information requirements for* NO_X compliance plans. (1) In accordance with § 72.40(a)(2) of this chapter, a complete compliance plan for NO_X shall, for each affected unit included in the permit application and subject to this part, either certify that the unit will comply with the applicable emissions limitation under § 76.5, 76.6, or 76.7 or specify one or more other Acid Rain compliance options for NO_X in accordance with the requirements of this part. A complete compliance plan for NO_X for a source shall include the following elements in a format prescribed by the Administrator:

(i) Identification of the source;

(ii) Identification of each affected unit that is at the source and is subject to this part;

(iii) Identification of the boiler type of each unit;

(iv) Identification of the compliance option proposed for each unit (i.e., meeting the applicable emissions limitation under §§ 76.5, 76.6, 76.7, 76.8 (early election), 76.10 (alternative emission limitation), 76.11 (NO_X emissions averaging), or 76.12 (Phase I NO_X compliance extension)) and any additional information required for the appropriate option in accordance with this part;

(v) Reference to the standard requirements in § 72.9 of this chapter (consistent with § 76.8(e)(1)(i)); and

(vi) The requirements of §§ 72.21 (a) and (b) of this chapter.

(d) *Duty to reapply.* The designated representative of any source with an affected unit subject to this part shall submit a complete Acid Rain permit application, including a complete compliance plan for NO_X emissions covering the unit, in accordance with the deadlines in § 72.30(c) of this chapter.

§ 76.10 Alternative emission limitations.

(a) General provisions. (1) The designated representative of an affected unit that is not an early election unit pursuant to § 76.8 and cannot meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7 using, for Group 1 boilers, either low NO_X burner technology or an alternative technology in accordance with paragraph (e)(11) of this section, or, for tangentially fired boilers, separated overfire air, or, for Group 2 boilers, the technology on which the applicable emission limitation is based may petition the permitting authority for an alternative emission limitation less stringent than the applicable emission limitation.

(2) In order for the unit to qualify for an alternative emission limitation, the designated representative shall demonstrate that the affected unit cannot meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7 based on a showing, to the satisfaction of the Administrator, that:

(i) (A) For a tangentially fired boiler, the owner or operator has either properly installed low NO_X burner technology or properly installed separated overfire air; or

(B) For a dry bottom wall-fired boiler (other than a unit applying cell burner technology), the owner or operator has properly installed low NO_X burner technology; or

(C) For a Group 1 boiler, the owner or operator has properly installed an alternative technology (including but not limited to reburning, selective noncatalytic reduction, or selective catalytic reduction) that achieves NO_X emission reductions demonstrated in accordance with paragraph (e)(11) of this section; or

(D) For a Group 2 boiler, the owner or operator has properly installed the appropriate NO_X emission control technology on which the applicable emission limitation in § 76.6 is based; and

(ii) The installed NO_X emission control system has been designed to meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7; and

(iii) For a demonstration period of at least 15 months or other period of time, as provided in paragraph (f)(1) of this section:

(A) The NO_X emission control system has been properly installed and properly operated according to specifications and procedures designed to minimize the emissions of NO_X to the atmosphere;

(B) Unit operating data as specified in this section show that the unit and NO_X emission control system were operated in accordance with the bid and design specifications on which the design of the NO_X emission control system was based; and

(C) Unit operating data as specified in this section, continuous emission monitoring data obtained pursuant to part 75 of this chapter, and the test data specific to the NO_X emission control system show that the unit could not meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7.

(b) *Petitioning process.* The petitioning process for an alternative emission limitation shall consist of the following steps:

(1) Operation during a period of at least 3 months, following the installation of the NO_X emission control system, that shows that the specific unit and the NO_X emission control system was unable to meet the applicable emissions limitation under §§ 76.5, 76.6, or 76.7 and was operated in accordance with the operating conditions upon which the design of the NO_X emission control system was based and with vendor specifications and procedures;

(2) Submission of a petition for an alternative emission limitation demonstration period as specified in paragraph (d) of this section;

(3) Operation during a demonstration period of at least 15 months, or other period of time as provided in paragraph (f)(1) of this section, that demonstrates the inability of the specific unit to meet the applicable emissions limitation under §§ 76.5, 76.6, or 76.7 and the minimum NO_X emissions rate that the specific unit can achieve during long-term load dispatch operation; and

(4) Submission of a petition for a final alternative emission limitation as specified in paragraph (e) of this section.

(c) *Deadlines.*—(1) *Petition for an alternative emission limitation demonstration period.* The designated representative of the unit shall submit a petition for an alternative emission limitation demonstration period to the permitting authority after the unit has been operated for at least 3 months after installation of the NO_X emission control system required under paragraph (a)(2) of this section and by the following deadline:

(i) For units that seek to have an alternative emission limitation demonstration period apply during all or part of calendar year 1996, or any previous calendar year by the later of:

(A) 120 days after startup of the NO_X emission control system, or

(B) May 1, 1996.

(ii) For units that seek an alternative emission limitation demonstration period beginning in a calendar year after 1996, not later than:

(A) 120 days after January 1 of that calendar year, or

(B) 120 days after startup of the NO_X emission control system if the unit is not operating at the beginning of that calendar year.

(2) *Petition for a final alternative emission limitation.* Not later than 90 days after the end of an approved alternative emission limitation demonstration period for the unit, the designated representative of the unit may submit a petition for an alternative emission limitation to the permitting authority.

(3) *Renewal of an alternative emission limitation.* In order to request continuation of an alternative emission limitation, the designated representative must submit a petition to renew the alternative emission limitation on the date that the application for renewal of the source's Acid Rain permit containing the alternative emission limitation is due.

(d) *Contents of petition for an alternative emission limitation demonstration period.* The designated representative of an affected unit that has met the minimum criteria under paragraph (a) of this section and that has been operated for a period of at least 3 months following the installation of the required NO_X emission control system may submit to the permitting authority a petition for an alternative emission limitation demonstration period. In the petition, the designated representative shall provide the following information in a format prescribed by the Administrator:

(1) Identification of the unit;

(2) The type of NO_X control technology installed (e.g., low NO_X burner technology, selective noncatalytic reduction, selective catalytic reduction, reburning);

(3) If an alternative technology is installed, the time period (not less than 6 consecutive months) prior to installation of the technology to be used for the demonstration required in paragraph (e)(11) of this section.

(4) Documentation as set forth in § 76.14(a)(1) showing that the installed NO_X emission control system has been designed to meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7 and that the system has been properly installed according to procedures and specifications designed to minimize the emissions of NO_X to the atmosphere;

(5) The date the unit commenced operation following the installation of the NO_X emission control system or the date the specific unit became subject to the emission limitations of §§ 76.5, 76.6, or 76.7, whichever is later;

(6) The dates of the operating period (which must be at least 3 months long);

(7) Certification by the designated representative that the owner(s) or operator operated the unit and the NO_X emission control system during the operating period in accordance with: Specifications and procedures designed to achieve the maximum NO_X reduction possible with the installed NO_X emission control system or the applicable emission limitation in §§ 76.5, 76.6, or 76.7; the operating conditions upon which the design of the NO_X emission control system was based; and vendor specifications and procedures;

(8) A brief statement describing the reason or reasons why the unit cannot achieve the applicable emission limitation in §§ 76.5, 76.6, or 76.7;

(9) A demonstration period plan, as set forth in § 76.14(a)(2);

(10) Unit operating data and quality-assured continuous emission monitoring data (including the specific data items listed in § 76.14(a)(3) collected in accordance with part 75 of this chapter during the operating period) and demonstrating the inability of the specific unit to meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7 on an annual average basis while operating as certified under paragraph (d)(7) of this section;

(11) An interim alternative emission limitation, in lb/mmBtu, that the unit can achieve during a demonstration period of at least 15 months. The interim alternative emission limitation shall be derived from the data specified in paragraph (d)(10) of this section using methods and procedures satisfactory to the Administrator;

(12) The proposed dates of the demonstration period (which must be at least 15 months long);

(13) A report which outlines the testing and procedures to be taken during the demonstration period in order to determine the maximum NO_X emission reduction obtainable with the installed system. The report shall include the reasons for the NO_X emission control system's failure to meet the applicable emission limitation, and the tests and procedures that will be followed to optimize the NO_X emission control system's performance. Such tests and procedures may include those identified in § 76.15 as appropriate.

(14) The special provisions at paragraph (g)(1) of this section.

(e) *Contents of petition for a final alternative emission limitation.* After the approved demonstration period, the designated representative of the unit may petition the permitting authority for an alternative emission limitation. The petition shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the unit;

(2) Certification that the owner(s) or operator operated the affected unit and the NO_X emission control system during the demonstration period in accordance with: specifications and procedures designed to achieve the maximum NO_X reduction possible with the installed NO_X emission control system or the applicable emissions limitation in §§ 76.5, 76.6, or 76.7; the operating conditions (including load dispatch conditions) upon which the design of the NO_X emission control system was based; and vendor specifications and procedures.

(3) Certification that the owner(s) or operator have installed in the affected unit all NO_X emission control systems, made any operational modifications, and completed any planned upgrades and/or maintenance to equipment specified in the approved demonstration period plan for optimizing NO_X emission reduction performance, consistent with the demonstration period plan and the proper operation of the installed NO_X emission control system. Such certification shall explain any differences between the installed NO_X emission control system and the equipment configuration described in the approved demonstration period plan.

(4) A clear description of each step or modification taken during the demonstration period to improve or optimize the performance of the installed NO_X emission control system.

(5) Engineering design calculations and drawings that show the technical specifications for installation of any additional operational or emission control modifications installed during the demonstration period.

(6) Unit operating and quality-assured continuous emission monitoring data (including the specific data listed in § 76.14(b)) collected in accordance with part 75 of this chapter during the demonstration period and demonstrating the inability of the specific unit to meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7 on an annual average basis while operating in accordance with the certification under paragraph (e)(2) of this section.

(7) A report (based on the parametric test requirements set forth in the approved demonstration period plan as identified in paragraph (d)(13) of this section), that demonstrates the unit was operated in accordance with the operating conditions upon which the

design of the NO_X emission control system was based and describes the reason or reasons for the failure of the installed NO_X emission control system to meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7 on an annual average basis.

(8) The minimum NO_X emission rate, in lb/mmBtu, that the affected unit can achieve on an annual average basis with the installed NO_X emission control system. This value, which shall be the requested alternative emission limitation, shall be derived from the data specified in this section using methods and procedures satisfactory to the Administrator and shall be the lowest annual emission rate the unit can achieve with the installed NO_X emission control system;

(9) All supporting data and calculations documenting the determination of the requested alternative emission limitation and its conformance with the methods and procedures satisfactory to the Administrator;

(10) The special provisions in paragraph (g)(2) of this section.

(11) In addition to the other requirements of this section, the owner or operator of an affected unit with a Group 1 boiler that has installed an alternative technology in addition to or in lieu of low NO_X burner technology and cannot meet the applicable emission limitation in § 76.5 shall demonstrate, to the satisfaction of the Administrator, that the actual percentage reduction in NO_X emissions (lbs/mmBtu), on an annual average basis is greater than 65 percent of the average annual NO_X emissions prior to the installation of the NO_X emission control system. The percentage reduction in NO_X emissions shall be determined using continuous emissions monitoring data for NO_X taken during the time period (under paragraph (d)(3) of this section) prior to the installation of the NO_X emission control system and during long-term load dispatch operation of the specific boiler.

(f) *Permitting authority's action.—(1) Alternative emission limitation demonstration period.* (i) The permitting authority may approve an alternative emission limitation demonstration period and demonstration period plan, provided that the requirements of this section are met to the satisfaction of the permitting authority. The permitting authority shall disapprove a demonstration period if the requirements of paragraph (a) of this section were not met during the operating period.

(ii) If the demonstration period is approved, the permitting authority will include, as part of the demonstration period, the 4 month period prior to submission of the application in the demonstration period.

(iii) The alternative emission limitation demonstration period will authorize the unit to emit at a rate not greater than the interim alternative emission limitation during the demonstration period on or after January 1, 1996 for Phase I units and the applicable date established in §§ 76.5(g) or 76.6 for Phase II units, and until the date that the Administrator approves or denies a final alternative emission limitation.

(iv) After an alternative emission limitation demonstration period is approved, if the designated representative requests an extension of the demonstration period in accordance with paragraph (g)(1)(i)(B) of this section, the permitting authority may extend the demonstration period by administrative amendment (under § 72.83 of this chapter) to the Acid Rain permit.

(v) The permitting authority shall deny the demonstration period if the designated representative cannot demonstrate that the unit met the requirements of paragraph (a)(2) of this section. In such cases, the permitting authority shall require that the owner or operator operate the unit in compliance with the applicable emission limitation in §§ 76.5, 76.6, or 76.7 for the period preceding the submission of the application for an alternative emission limitation demonstration period, including the operating period, if such periods are after the date on which the unit is subject to the standard limit under §§ 76.5, 76.6, or 76.7.

(2) *Alternative emission limitation.* (i) If the permitting authority determines that the requirements in this section are met, the permitting authority will approve an alternative emission limitation and issue or revise an Acid Rain permit to apply the approved limitation, in accordance with subparts F and G of part 72 of this chapter. The permit will authorize the unit to emit at a rate not greater than the approved alternative emission limitation, starting the date the permitting authority revises an Acid Rain permit to approve an alternative emission limitation.

(ii) If a permitting authority disapproves an alternative emission limitation under paragraph (a)(2) of this section, the owner or operator shall operate the affected unit in compliance with the applicable emission limitation in §§ 76.5, 76.6, or 76.7 (unless the unit is participating in an approved averaging plan under § 76.11) beginning on the date the permitting authority revises an Acid Rain permit to disapprove an alternative emission limitation.

(3) *Alternative emission limitation renewal.* (i) If, upon review of a petition to renew an approved alternative emission limitation, the permitting authority determines that no changes have been made to the control technology, its operation, the operating conditions on which the alternative emission limitation was based, or the actual NO_X emission rate, the alternative emission limitation will be renewed.

(ii) If the permitting authority determines that changes have been made to the control technology, its operation, the fuel quality, or the operating conditions on which the alternative emission limitation was based, the designated representative shall submit, in order to renew the alternative emission limitation or to obtain a new alternative emission limitation, a petition for an alternative emission limitation demonstration period that meets the requirements of paragraph (d) of this section using a new demonstration period.

(g) *Special provisions.*—(1) *Alternative emission limitation demonstration period.* (i) *Emission limitations.* (A) Each unit with an approved alternative emission limitation demonstration period shall comply with the interim emission limitation specified in the unit's permit beginning on the effective date of the demonstration period specified in the permit and, if a timely petition for a final alternative emission limitation is submitted, extending until the date on which the permitting authority issues or revises an Acid Rain permit to approve or disapprove an alternative emission limitation. If a timely petition is not submitted, then the unit shall comply with the standard emission limit under §§ 76.5, 76.6, or 76.7 beginning on the date the petition was required to be submitted under paragraph (c)(2) of this section.

(B) When the owner or operator identifies, during the demonstration period, boiler operating or NO_X emission control system modifications or upgrades that would produce further NO_X emission reductions, enabling the affected unit to comply with or bring its emission rate closer to the applicable emissions limitation under §§ 76.5, 76.6, or 76.7, the designated representative may submit a request and the permitting authority may grant, by administrative amendment under § 72.83 of this chapter, an extension of the demonstration period for such period of time (not to exceed 12 months) as may be necessary to implement such modifications or upgrades.

(C) If the approved interim alternative emission limitation applies to a unit for part, but not all, of a calendar year, the unit shall determine compliance for the calendar year in accordance with the procedures in § 76.13(a).

(ii) *Operating requirements.* (A) A unit with an approved alternative emission limitation demonstration period shall be operated under load dispatch conditions consistent with the operating conditions upon which the design of the NO_X emission control system and performance guarantee were based, and in accordance with the demonstration period plan.

(B) A unit with an approved alternative emission limitation demonstration period shall install all NO_X emission control systems, make any operational modifications, and complete any upgrades and maintenance to equipment specified in the approved demonstration period plan for optimizing NO_X emission reduction performance.

(C) When the owner or operator identifies boiler or NO_X emission control system operating modifications that would produce higher NO_X emission reductions, enabling the affected unit to comply with, or bring its emission rate closer to, the applicable emission limitation under §§ 76.5, 76.6, or 76.7, the designated representative shall submit an administrative amendment under § 72.83 of this chapter to revise the unit's Acid Rain permit and demonstration period plan to include such modifications.

(iii) *Testing requirements.* A unit with an approved alternative emission limitation demonstration period shall monitor in accordance with part 75 of this chapter and shall conduct all tests required under the approved demonstration period plan.

(2) *Final alternative emission limitation.*—(i) *Emission limitations.* (A) Each unit with an approved alternative emission limitation shall comply with the alternative emission limitation specified in the unit's permit beginning on the date specified in the permit as issued or revised by the permitting authority to apply the final alternative emission limitation.

(B) If the approved interim or final alternative emission limitation applies to a unit for part, but not all, of a calendar year, the unit shall determine compliance for the calendar year in accordance with the procedures in § 76.13(a).

§ 76.11 Emissions averaging.

(a) *General provisions.* In lieu of complying with the applicable emission limitation in §§ 76.5, 76.6, or 76.7, any affected units subject to such emission limitation, under control of the same owner or operator, and having the same designated representative may average their NO_X emissions under an averaging plan approved under this section.

(1) Each affected unit included in an averaging plan for Phase I shall be a Phase I unit with a Group 1 boiler subject to an emission limitation in § 76.5 during all years for which the unit is included in the plan.

(i) If a unit with an approved NO_X compliance extension is included in an averaging plan for 1996, the unit shall be treated, for the purposes of applying Equation 1 in paragraph (a)(6) of this section and Equation 2 in paragraph (d)(1)(ii)(A) of this section, as subject to the applicable emissions limitation under § 76.5 for the entire year 1996.

(ii) A Phase II unit approved for early election under § 76.8 shall not be included in an averaging plan for Phase I.

(2) Each affected unit included in an averaging plan for Phase II shall be a boiler subject to an emission limitation in §§ 76.5, 76.6, or 76.7 for all years for which the unit is included in the plan.

(3) Each unit included in an averaging plan shall have an alternative contemporaneous annual emission limitation (lb/mmBtu) and can only be included in one averaging plan.

(4) Each unit included in an averaging plan shall have a minimum allowable annual heat input value (mmBtu), if it has an alternative contemporaneous annual emission limitation more stringent than that unit's applicable emission limitation under §§ 76.5, 76.6, or 76.7, and a maximum allowable annual heat input value, if it has an alternative contemporaneous annual emission limitation less stringent than that unit's applicable emission limitation under §§ 76.5, 76.6, or 76.7.

(5) The Btu-weighted annual average emission rate for the units in an averaging plan shall be less than or equal to the Btu-weighted annual average emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations in §§ 76.5, 76.6, or 76.7.

(6) In order to demonstrate that the proposed plan is consistent with paragraph (a)(5) of this section, the alternative contemporaneous annual emission limitations and annual heat input values assigned to the units in the proposed averaging plan shall meet the following requirement:

$$\frac{\sum_{i=1}^{n}\left(R_{Li} \times HI_i\right)}{\sum_{i=1}^{n} HI_i} \le \frac{\sum_{i=1}^{n}\left(R_{li} \times HI_i\right)}{\sum_{i=1}^{n} HI_i} \qquad (\text{Equation 1})$$

Where:

R_{Li} = Alternative contemporaneous annual emission limitation for unit i, lb/mmBtu, as specified in the averaging plan;

R_{li} = Applicable emission limitation for unit i, lb/mmBtu, as specified in §§ 76.5, 76.6, or 76.7 except that for early election units, which may be included in an averaging plan only on or after January 1, 2000, R_{li} shall equal the most stringent applicable emission limitation under §§ 76.5 or 76.7;

HI_i = Annual heat input for unit i, mmBtu, as specified in the averaging plan;

n = Number of units in the averaging plan.

(7) For units with an alternative emission limitation, R_{li} shall equal the applicable emissions limitation under §§ 76.5, 76.6, or 76.7, not the alternative emissions limitation.

(8) No unit may be included in more than one averaging plan.

(b)(1) *Submission requirements.* The designated representative of a unit meeting the requirements of paragraphs (a)(1), (a)(2), and (a)(8) of this section may submit an averaging plan (or a revision to an approved averaging plan) to the permitting authority(ies) at any time up to and including January 1 (or July 1, if the plan is restricted to units located within a single permitting authority's jurisdiction) of the calendar year for which the averaging plan is to become effective.

(2) The designated representative shall submit a copy of the same averaging plan (or the same revision to an approved averaging plan) to each permitting authority with jurisdiction over a unit in the plan.

(3) When an averaging plan (or a revision to an approved averaging plan) is not approved, the owner or operator of each unit in the plan shall operate the unit in compliance with the emission limitation that would apply in the absence of the averaging plan (or revision to a plan).

(c) *Contents of NO_X averaging plan.* A complete NO_X averaging plan shall include the following elements in a format prescribed by the Administrator:

(1) Identification of each unit in the plan;

(2) Each unit's applicable emission limitation in §§ 76.5, 76.6, or 76.7;

(3) The alternative contemporaneous annual emission limitation for each unit (in lb/mmBtu). If any of the units identified in the NO_X averaging plan utilize a common stack pursuant to § 75.17(a)(2)(i)(B) of this chapter, the same alternative contemporaneous emission limitation shall be assigned to each such unit and different heat input limits may be assigned;

(4) The annual heat input limit for each unit (in mmBtu);

(5) The calculation for Equation 1 in paragraph (a)(6) of this section;

(6) The calendar years for which the plan will be in effect; and

(7) The special provisions in paragraph (d)(1) of this section.

(d) *Special provisions.—(1) Emission limitations.* Each affected unit in an approved averaging plan is in compliance with the Acid Rain emission limitation for NO_X under the plan only if the following requirements are met:

(i) For each unit, the unit's actual annual average emission rate for the calendar year, in lb/mmBtu, is less than or equal to its alternative contemporaneous annual emission limitation in the averaging plan; and

(A) For each unit with an alternative contemporaneous emission limitation less stringent than the applicable emission limitation in §§ 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year does not exceed the annual heat input limit in the averaging plan;

(B) For each unit with an alternative contemporaneous annual emission limitation more stringent than the applicable emission limitation in §§ 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year is not less than the annual heat input limit in the averaging plan; or

(ii) If one or more of the units does not meet the requirements under paragraph (d)(1)(i) of this section, the designated representative shall demonstrate, in accordance with paragraph (d)(1)(ii)(A) of this section (Equation 2) that the actual Btu-weighted annual average emission rate for the units in the plan is less than or equal to the Btu-weighted annual average rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations in §§ 76.5, 76.6, or 76.7.

(A) A group showing of compliance shall be made based on the following equation:

$$\frac{\sum_{i=1}^{n}\left(R_{ai} \times HI_{ai}\right)}{\sum_{i=1}^{n} HI_{ai}} \leq \frac{\sum_{i=1}^{n}\left(R_{li} \times HI_{ai}\right)}{\sum_{i=1}^{n} HI_{ai}} \qquad \text{(Equation 2)}$$

Where:

R_{ai} = Actual annual average emission rate for unit i, lb/mmBtu, as determined using the procedures in part 75 of this chapter. For units in an averaging plan utilizing a common stack pursuant to § 75.17(a)(2)(i)(B) of this chapter, use the same NO_X emission rate value for each unit utilizing the common stack, and calculate this value in accordance with appendix F to part 75 of this chapter;

R_{li} = Applicable annual emission limitation for unit i lb/mmBtu, as specified in §§ 76.5, 76.6, or 76.7, except that for early election units, which may be included in an averaging plan only on or after January 1, 2000, R_{li} shall equal the most stringent applicable emission limitation under §§ 76.5 or 76.7;

HI_{ai} = Actual annual heat input for unit i, mmBtu, as determined using the procedures in part 75 of this chapter;

n = Number of units in the averaging plan.

(B) For units with an alternative emission limitation, R_{li} shall equal the applicable emission limitation under §§ 76.5, 76.6, or 76.7, not the alternative emission limitation.

(C) If there is a successful group showing of compliance under paragraph (d)(1)(ii)(A) of this section for a calendar year, then all units in the averaging plan shall be deemed to be in compliance for that year with their alternative contemporaneous emission limitations and annual heat input limits under paragraph (d)(1)(i) of this section.

(2) *Liability.* The owners and operators of a unit governed by an approved averaging plan shall be liable for any violation of the plan or this section at that unit or any other unit in the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and sections 113 and 411 of the Act.

(3) *Withdrawal or termination.* The designated representative may submit a notification to terminate an approved averaging plan in accordance with § 72.40(d) of this chapter, no later than October 1 of the calendar year for which the plan is to be withdrawn or terminated.

§ 76.12 Phase I NO_X compliance extension.

(a) *General provisions.* (1) The designated representative of a Phase I unit with a Group 1 boiler may apply for and receive a 15-month extension of the deadline for meeting the applicable emissions limitation under § 76.5 where it is demonstrated, to the satisfaction of the Administrator, that:

(i) The low NO_X burner technology designed to meet the applicable emission limitation is not in adequate supply to enable installation and operation at the unit, consistent with system reliability, by January 1, 1995 and the reliability problems are due substantially to NO_X emission control system installation and availability; or

(ii) The unit is participating in an approved clean coal technology demonstration project.

(2) In order to obtain a Phase I NO_X compliance extension, the designated representative shall submit a Phase I

NO_X compliance extension plan by October 1, 1994.

(b) *Contents of Phase I NO_X compliance extension plan.* A complete Phase I NO_X compliance extension plan shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the unit.

(2) For units applying pursuant to paragraph (a)(1)(i) of this section:

(i) A list of the company names, addresses, and telephone numbers of vendors who are qualified to provide the services and low NO_X burner technology designed to meet the applicable emission limitation under § 76.5 and have been contacted to obtain the required services and technology. The list shall include the dates of contact, and a copy of each request for bids shall be submitted, along with any other information necessary to show a good-faith effort to obtain the required services and technology necessary to meet the requirements of this part on or before January 1, 1995.

(ii) A copy of those portions of a legally binding contract with a qualified vendor that demonstrate that services and low NO_X burner technology designed to meet the applicable emission limitation under § 76.5, with a completion date not later than December 31, 1995 have been contracted for.

(iii) Scheduling information, including justification and test schedules.

(iv) To demonstrate, if applicable, that the supply of the low NO_X burner technology designed to meet the applicable emission limitation under § 76.5 is inadequate to enable its installation and operation at the unit, consistent with system reliability, in time for the unit to comply with the applicable emission limitation on or before January 1, 1995, either:

(A) Certification from the selected vendor(s) (by a certifying official) listed in paragraph (b)(2)(i) of this section stating that they cannot provide the necessary services and install the low NO_X burner technology on or before January 1, 1995 and explaining the reasons why the services cannot be provided and why the equipment cannot be installed in a timely manner; or

(B) The following information:

(i) Standard load forecasts, based on standard forecasting models available throughout the utility industry and applied to the period, January 1, 1993, through December 31, 1994.

(ii) Specific reasons why an outage cannot be scheduled to enable the unit to install and operate the low NO_X burner technology by January 1, 1995, including reasons why no other units can be used to replace this unit's generation during such outage.

(iii) Fuel and energy balance summaries and power and other consumption requirements (including those for air, steam, and cooling water).

(3) To demonstrate, if applicable, participation in an approved clean coal technology demonstration project, a description of the project, including all sources of federal, State, and other outside funding, amount and date for approval of federal funding, the duration of the project, and the anticipated completion date of the project.

(4) The special provisions in paragraph (d) of this section.

(c) (1) *Administrator's action.* To the extent the Administrator determines that a Phase I NO_X compliance extension plan complies with the requirements of this section, the Administrator will approve the plan and revise the Acid Rain permit governing the unit in the plan in order to incorporate the plan by administrative amendment under § 72.83 of this chapter, except that the Administrator shall have 90 days from receipt of the compliance extension plan to take final action.

(2) The Administrator will approve or disapprove a proposed NO_X compliance extension plan within 3 months of receipt.

(d) *Special provisions.*

(1) Emission limitations. The unit shall comply with the applicable emission limitation under § 76.5 beginning April 1, 1996. Compliance shall be determined as specified in part 75 of this chapter using measured values of NO_X emissions and heat input only for the portion of the year that the emission limit is in effect.

(2) If a unit with an approved NO_X compliance extension is included in an averaging plan under § 76.11 for year 1996, the unit shall be treated, for purposes of applying Equation 1 in § 76.11(a)(6) and Equation 2 in § 76.11(d)(1)(ii)(A), as subject to the applicable emission limitation under § 76.5 for the entire year 1996.

(e) *Extension until December 31, 1997.* (1) The designated representative of a Phase I unit that is subject to section 404(d) of the Act, has a tangentially fired boiler, and is unable to install low NO_X burner technology by January 1, 1997 may submit a petition for and receive an extension for meeting the applicable emission limitation under § 76.5 where it is demonstrated, to the satisfaction of the Administrator, that:

(i) The unit is located at a source with two or more other units, all of which are Phase I units that are subject to section 404(d) of the Act and have tangentially fired boilers;

(ii) The NO_X control system at the unit was scheduled to be installed by January 1, 1997 and, because of operational problems associated with the NO_X control system, will be redesigned; and

(iii) Installation of the redesigned low NO_X burner technology at the unit cannot be completed by January 1, 1997 without causing system reliability problems.

(2) A complete petition shall include the following elements and shall be submitted by April 28, 1995.

(i) Identification of the unit and the other units at the source;

(ii) A statement describing how the requirements of paragraphs (e)(1)(ii) and (e)(1)(iii) of this section are met;

(iii) The earliest date, not later than December 31, 1997, by which installation of the redesigned low NO_X burner technology can be completed consistent with system reliability; and

(iv) The provisions in paragraph (e)(4) of this section.

(3) To the extent the Administrator determines that a Phase I unit meets the requirements of paragraphs (e)(1) and (e)(2) of this section, the Administrator will approve the petition within 90 days from receipt of the complete petition. The Acid Rain permit governing the unit will be revised in order to incorporate the approved extension, which shall terminate no later than December 31, 1997, by administrative amendment under § 72.83 of this chapter except that the Administrator will have 90 days to take final action.

(4) The unit shall comply with the applicable emission limitation under § 76.5 beginning on the day immediately following the day on which the extension approved under paragraph (e)(3) of this section terminates. Compliance shall be determined as specified in part 75 of this chapter using measured values of NO_X emissions and heat input only for the portion of the year that the emission limit is in effect. If a unit with an approved extension is included in an averaging plan under § 76.11 for year 1997, the unit shall be treated, for the purpose of applying Equation 1 in § 76.11(a)(6) and Equation 2 in § 76.11(d)(1)(ii)(A), as subject to the applicable emission limitation under § 76.5 for the entire year 1997.

§ 76.13 Compliance and excess emissions.

Excess emissions of nitrogen oxides under § 77.6 of this chapter shall be calculated as follows:

(a) For a unit that is not in an approved averaging plan:

(1) Calculate EE_i for each portion of the calendar year that the unit is subject to a different NO_X emission limitation:

$$EE_i = \frac{(R_{ai} - R_{li}) \times HI_i}{2000} \qquad \text{(Equation 3)}$$

Where:

EE_i = Excess emissions for NO_X for the portion of the calendar year (in tons);

R_{ai} = Actual average emission rate for the unit (in lb/mmBtu), determined according to part 75 of this chapter for the portion of the calendar year for which the applicable emission limitation R_l is in effect;

R_{li} = Applicable emission limitation for the unit, (in lb/mmBtu), as specified in §§ 76.5, 76.6, or 76.7 or as determined under § 76.10;

$$EE = \sum_{i=1}^{n} EE_i \qquad \text{(Equation 4)}$$

HI^i = Actual heat input for the unit, (in mmBtu), determined according to part 75 of this chapter for the portion of the calendar year for which the applicable emission limitation, R_l, is in effect.

(2) If EE_i is a negative number for any portion of the calendar year, the EE value for that portion of the calendar year shall be equal to zero (e.g., if $EE_i = -100$, then $EE_i = 0$).

(3) Sum all EE_i values for the calendar year:

Where:

EE = Excess emissions for NO_X for the year (in tons);

n = The number of time periods during which a unit is subject to different emission limitations; and

(b) For units participating in an approved averaging plan, when all the requirements under § 76.11(d)(1) are not met,

$$EE = \frac{\sum_{i=1}^{n} (R_{ai} \times HI_i) - \sum_{i=1}^{n} (R_{li} \times HI_i)}{2000} \qquad \text{(Equation 5)}$$

Where:

EE = Excess emissions for NO_X for the year (in tons);

R_{ai} = Actual annual average emission rate for NO_X for unit i, (in lb/mmBtu), determined according to part 75 of this chapter;

R_{li} = Applicable emission limitation for unit i, (in lb/mmBtu), as specified in §§ 76.5, 76.6, or 76.7;

HI_i = Actual annual heat input for unit i, mmBtu, determined according to part 75 of this chapter;

n = Number of units in the averaging plan.

§ 76.14 Monitoring, recordkeeping, and reporting.

(a) A petition for an alternative emission limitation demonstration period under § 76.10(d) shall include the following information:

(1) In accordance with § 76.10(d)(4), the following information:

(i) Documentation that the owner or operator solicited bids for a NO_X emission control system designed for application to the specific boiler and designed to achieve the applicable emission limitation in §§ 76.5, 76.6, or 76.7 on an annual average basis. This documentation must include a copy of all bid specifications.

(ii) A copy of the performance guarantee submitted by the vendor of the installed NO_X emission control system to the owner or operator showing that such system was designed to meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7 on an annual average basis.

(iii) Documentation describing the operational and combustion conditions that are the basis of the performance guarantee.

(iv) Certification by the primary vendor of the NO_X emission control system that such equipment and associated auxiliary equipment was properly installed according to the modifications and procedures specified by the vendor.

(v) Certification by the designated representative that the owner(s) or operator installed technology that meets the requirements of § 76.10(a)(2).

(2) In accordance with § 76.10(d)(9), the following information:

(i) The operating conditions of the NO_X emission control system including load range, O_2 range, coal volatile matter range, and, for tangentially fired boilers, distribution of combustion air within the NO_X emission control system;

(ii) Certification by the designated representative that the owner(s) or operator have achieved and are following the operating conditions, boiler modifications, and upgrades that formed the basis for the system design and performance guarantee;

(iii) Any planned equipment modifications and upgrades for the purpose of achieving the maximum NO_X reduction performance of the NO_X emission control system that were not included in the design specifications and performance guarantee, but that were achieved prior to submission of this application and are being followed;

(iv) A list of any modifications or replacements of equipment that are to be done prior to the completion of the demonstration period for the purpose of reducing emissions of NO_X; and

(v) The parametric testing that will be conducted to determine the reason or reasons for the failure of the unit to achieve the applicable emission limitation and to verify the proper operation of the installed NO_X emission control system during the demonstration period. The tests shall include tests in § 76.15, which may be modified as follows:

(A) The owner or operator of the unit may add tests to those listed in § 76.15, if such additions provide data relevant to the failure of the installed NO_X emission control system to meet the applicable emissions limitation in §§ 76.5, 76.6, or 76.7; or

(B) The owner or operator of the unit may remove tests listed in § 76.15 that are shown, to the satisfaction of the permitting authority, not to be relevant to NO_X emissions from the affected unit; and

(C) In the event the performance guarantee or the NO_X emission control system specifications require additional tests not listed in § 76.15, or specify operating conditions not verified by tests listed in § 76.15, the owner or operator of the unit shall include such additional tests.

(3) In accordance with § 76.10(d)(10), the following information for the operating period:

(i) The average NO_X emission rate (in lb/mmBtu) of the specific unit;

(ii) The highest hourly NO_X emission rate (in lb/mmBtu) of the specific unit;

(iii) Hourly NO_X emission rate (in lb/mmBtu), calculated in accordance with part 75 of this chapter;

(iv) Total heat input (in mmBtu) for the unit for each hour of operation, calculated in accordance with the requirements of part 75 of this chapter; and

(v) Total integrated hourly gross unit load (in MWge).

(b) A petition for an alternative emission limitation shall include the following information in accordance with § 76.10(e)(6).

(1) Total heat input (in mmBtu) for the unit for each hour of operation, calculated in accordance with the requirements of part 75 of this chapter;

(2) Hourly NO_X emission rate (in lb/mmBtu), calculated in accordance with the requirements of part 75 of this chapter; and

(3) Total integrated hourly gross unit load (MWge).

(c) *Reporting of the costs of low NO_X burner technology applied to Group 1, Phase I boilers.* (1) Except as provided in paragraph (c)(2) of this section, the designated representative of a Phase I unit with a Group 1 boiler that has installed or is installing any form of low NO_X burner technology shall submit to the Administrator a report containing the capital cost, operating cost, and baseline and post-retrofit emission data specified in appendix B to this part. If any of the required equipment, cost, and schedule information are not available (e.g., the retrofit project is still underway), the designated representative shall include in the report detailed cost estimates and other projected or estimated data in lieu of the information that is not available.

(2) The report under paragraph (c)(1) of this section is not required with regard to the following types of Group 1, Phase I units:

(i) Units employing no new NO_X emission control system after November 15, 1990;

(ii) Units employing modifications to boiler operating parameters (e.g., burners out of service or fuel switching) without low NO_X burners or other emission reduction equipment for reducing NO_X emissions;

(iii) Units with wall-fired boilers employing only overfire air and units with tangentially fired boilers employing only separated overfire air; or

(iv) Units beginning installation of a new NO_X emission control system after August 11, 1995.

(3) The report under paragraph (c)(1) of this section shall be submitted to the Administrator by:

(i) 120 days after completion of the low NO_X burner technology retrofit project; or

(ii) May 23, 1995, if the project was completed on or before January 23, 1995.

§ 76.15 Test methods and procedures.

(a) The owner or operator may use the following tests as a basis for the report required by § 76.10(e)(7):

(1) Conduct an ultimate analysis of coal using ASTM D 3176–89 (incorporated by reference as specified in § 76.4);

(2) Conduct a proximate analysis of coal using ASTM D 3172–89 (incorporated by reference as specified in § 76.4); and

(3) Measure the coal mass flow rate to each individual burner using ASME Power Test Code 4.2 (1991), ‘‘Test Code for Coal Pulverizers’’ or ISO 9931 (1991), ‘‘Coal—Sampling of Pulverized Coal Conveyed by Gases in Direct Fired Coal Systems’’ (incorporated by reference as specified in § 76.4).

(b) The owner or operator may measure and record the actual NO_X emission rate in accordance with the requirements of this part while varying the following parameters where possible to determine their effects on the emissions of NO_X from the affected boiler:

(1) Excess air levels;

(2) Settings of burners or coal and air nozzles, including tilt and yaw, or swirl;

(3) For tangentially fired boilers, distribution of combustion air within the NO_X emission control system;

(4) Coal mass flow rates to each individual burner;

(5) Coal-to-primary air ratio (based on pound per hour) for each burner, the average coal-to-primary air ratio for all burners, and the deviations of individual burners' coal-to-primary air ratios from the average value; and

(6) If the boiler uses varying types of coal, the type of coal. Provide the results of proximate and ultimate analyses of each type of as-fired coal.

(c) In performing the tests specified in paragraph (a) of this section, the owner or operator shall begin the tests using the equipment settings for which the NO_X emission control system was designed to meet the NO_X emission rate guaranteed by the primary NO_X emission control system vendor. These results constitute the ‘‘baseline controlled’’ condition.

(d) After establishing the baseline controlled condition under paragraph (c) of this section, the owner or operator may:

(1) Change excess air levels ± 5 percent from the baseline controlled condition to determine the effects on emissions of NO_X, by providing a minimum of three readings (e.g., with a baseline reading of 20 percent excess air, excess air levels will be changed to 19 percent and 21 percent);

(2) For tangentially fired boilers, change the distribution of combustion air within the NO_X emission control system to determine the effects on NO_X emissions by providing a minimum of three readings, one with the minimum, one with the baseline, and one with the maximum amounts of staged combustion air; and

(3) Show that the combustion process within the boiler is optimized (e.g., that the burners are balanced).

§ 76.16 [Reserved]

Appendix A to Part 76—Phase I Affected Coal-Fired Utility Units With Group 1 or Cell Burner Boilers

TABLE 1.—PHASE I TANGENTIALLY FIRED UNITS

State	Plant	Unit	Operator
ALABAMA	EC GASTON	5	ALABAMA POWER CO.
GEORGIA	BOWEN	1BLR	GEORGIA POWER CO.
GEORGIA	BOWEN	2BLR	GEORGIA POWER CO.
GEORGIA	BOWEN	3BLR	GEORGIA POWER CO.
GEORGIA	BOWEN	4BLR	GEORGIA POWER CO.
GEORGIA	JACK MCDONOUGH	MB1	GEORGIA POWER CO.
GEORGIA	JACK MCDONOUGH	MB2	GEORGIA POWER CO.
GEORGIA	WANSLEY	1	GEORGIA POWER CO.
GEORGIA	WANSLEY	2	GEORGIA POWER CO.
GEORGIA	YATES	Y1BR	GEORGIA POWER CO.
GEORGIA	YATES	Y2BR	GEORGIA POWER CO.
GEORGIA	YATES	Y3BR	GEORGIA POWER CO.
GEORGIA	YATES	Y4BR	GEORGIA POWER CO.
GEORGIA	YATES	Y5BR	GEORGIA POWER CO.

TABLE 1.—PHASE I TANGENTIALLY FIRED UNITS—Continued

State	Plant	Unit	Operator
GEORGIA	YATES	Y6BR	GEORGIA POWER CO.
GEORGIA	YATES	Y7BR	GEORGIA POWER CO.
ILLINOIS	BALDWIN	3	ILLINOIS POWER CO.
ILLINOIS	HENNEPIN	2	ILLINOIS POWER CO.
ILLINOIS	JOPPA	1	ELECTRIC ENERGY INC.
ILLINOIS	JOPPA	2	ELECTRIC ENERGY INC.
ILLINOIS	JOPPA	3	ELECTRIC ENERGY INC.
ILLINOIS	JOPPA	4	ELECTRIC ENERGY INC.
ILLINOIS	JOPPA	5	ELECTRIC ENERGY INC.
ILLINOIS	JOPPA	6	ELECTRIC ENERGY INC.
ILLINOIS	MEREDOSIA	5	CEN ILLINOIS PUB SER.
ILLINOIS	VERMILION	2	ILLINOIS POWER CO.
INDIANA	CAYUGA	1	PSI ENERGY INC.
INDIANA	CAYUGA	2	PSI ENERGY INC.
INDIANA	EW STOUT	50	INDIANAPOLIS PWR & LT.
INDIANA	EW STOUT	60	INDIANAPOLIS PWR & LT.
INDIANA	EW STOUT	70	INDIANAPOLIS PRW & LT.
INDIANA	HT PRITCHARD	6	INDIANAPOLIS PWR & LT.
INDIANA	PETERSBURG	1	INDIANAPOLIS PWR & LT.
INDIANA	PETERSBURG	2	INDIANAPOLIS PWR & LT.
INDIANA	WABASH RIVER	6	PSI ENERGY INC.
IOWA	BURLINGTON	1	IOWA SOUTHERN UTL.
IOWA	ML KAPP	2	INTERSTATE POWER CO.
IOWA	RIVERSIDE	9	IOWA-ILL GAS & ELEC.
KENTUCKY	ELMER SMITH	2	OWENSBORO MUN UTIL.
KENTUCKY	EW BROWN	2	KENTUCKY UTL CO.
KENTUCKY	EW BROWN	3	KENTUCKY UTL CO.
KENTUCKY	GHENT	1	KENTUCKY UTL CO.
MARYLAND	MORGANTOWN	1	POTOMAC ELEC PWR CO.
MARYLAND	MORGANTOWN	2	POTOMAC ELEC PWR CO.
MICHIGAN	JH CAMPBELL	1	CONSUMERS POWER CO.
MISSOURI	LABADIE	1	UNION ELECTRIC CO.
MISSOURI	LABADIE	2	UNION ELECTRIC CO.
MISSOURI	LABADIE	3	UNION ELECTRIC CO.
MISSOURI	LABADIE	4	UNION ELECTRIC CO.
MISSOURI	MONTROSE	1	KANSAS CITY PWR & LT.
MISSOURI	MONTROSE	2	KANSAS CITY PWR & LT.
MISSOURI	MONTROSE	3	KANSAS CITY PWR & LT.
NEW YORK	DUNKIRK	3	NIAGARA MOHAWK PWR.
NEW YORK	DUNKIRK	4	NIAGARA MOHAWK PWR.
NEW YORK	GREENIDGE	6	NY STATE ELEC & GAS.
NEW YORK	MILLIKEN	1	NY STATE ELEC & GAS.
NEW YORK	MILLIKEN	2	NY STATE ELEC & GAS.
OHIO	ASHTABULA	7	CLEVELAND ELEC ILLUM.
OHIO	AVON LAKE	11	CLEVELAND ELEC ILLUM.
OHIO	CONESVILLE	4	COLUMBUS STHERN PWR.
OHIO	EASTLAKE	1	CLEVELAND ELEC ILLUM.
OHIO	EASTLAKE	2	CLEVELAND ELEC ILLUM.
OHIO	EASTLAKE	3	CLEVELAND ELEC ILLUM.
OHIO	EASTLAKE	4	CLEVELAND ELEC ILLUM.
OHIO	MIAMI FORT	6	CINCINNATI GAS & ELEC.
OHIO	WC BECKJORD	5	CINCINNATI GAS & ELEC.
OHIO	WC BECKJORD	6	CINCINNATI GAS & ELEC.
PENNSYLVANIA	BRUNNER ISLAND	1	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	BRUNNER ISLAND	2	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	BRUNNER ISLAND	3	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	CHESWICK	1	DUQUESNE LIGHT CO.
PENNSYLVANIA	CONEMAUGH	1	PENNSYLVANIA ELEC CO.
PENNSYLVANIA	CONEMAUGH	2	PENNSYLVANIA ELEC CO.
PENNSYLVANIA	PORTLAND	1	METROPOLITAN EDISON.
PENNSYLVANIA	PORTLAND	2	METROPOLITAN EDISON.
PENNSYLVANIA	SHAWVILLE	3	PENNSYLVANIA ELEC CO.
PENNSYLVANIA	SHAWVILLE	4	PENNSYLVANIA ELEC CO.
TENNESSEE	GALLATIN	1	TENNESSEE VAL AUTH.
TENNESSEE	GALLATIN	2	TENNESSEE VAL AUTH.
TENNESSEE	GALLATIN	3	TENNESSEE VAL AUTH.
TENNESSEE	GALLATIN	4	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	1	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	2	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	3	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	4	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	5	TENNESSEE VAL AUTH.

TABLE 1.—PHASE I TANGENTIALLY FIRED UNITS—Continued

State	Plant	Unit	Operator
TENNESSEE	JOHNSONVILLE	6	TENNESSEE VAL AUTH.
WEST VIRGINIA	ALBRIGHT	3	MONONGAHELA POWER CO.
WEST VIRGINIA	FORT MARTIN	1	MONONGAHELA POWER CO.
WEST VIRGINIA	MOUNT STORM	1	VIRGINIA ELEC & PWR.
WEST VIRGINIA	MOUNT STORM	2	VIRGINIA ELEC & PWR.
WEST VIRGINIA	MOUNT STORM	3	VIRGINIA ELEC & PWR.
WISCONSIN	GENOA	1	DAIRYLAND POWER COOP.
WISCONSIN	SOUTH OAK CREEK	7	WISCONSIN ELEC POWER.
WISCONSIN	SOUTH OAK CREEK	8	WISCONSIN ELEC POWER.

TABLE 2.—PHASE I DRY BOTTOM-FIRED UNITS

State	Plant	Unit	Operator
ALABAMA	COLBERT	1	TENNESSEE VAL AUTH.
ALABAMA	COLBERT	2	TENNESSEE VAL AUTH.
ALABAMA	COLBERT	3	TENNESSEE VAL AUTH.
ALABAMA	COLBERT	4	TENNESSEE VAL AUTH.
ALABAMA	COLBERT	5	TENNESSEE VAL AUTH.
ALABAMA	EC GASTON	1	ALABAMA POWER CO.
ALABAMA	EC GASTON	2	ALABAMA POWER CO.
ALABAMA	EC GASTON	3	ALABAMA POWER CO.
ALABAMA	EC GASTON	4	ALABAMA POWER CO.
FLORIDA	CRIST	6	GULF POWER CO.
FLORIDA	CRIST	7	GULF POWER CO.
GEORGIA	HAMMOND	1	GEORGIA POWER CO.
GEORGIA	HAMMOND	2	GEORGIA POWER CO.
GEORGIA	HAMMOND	3	GEORGIA POWER CO.
GEORGIA	HAMMOND	4	GEORGIA POWER CO.
ILLINOIS	GRAND TOWER	9	CEN ILLINOIS PUB SER.
INDIANA	CULLEY	2	STHERN IND GAS & EL.
INDIANA	CULLEY	3	STHERN IND GAS & EL.
INDIANA	GIBSON	1	PSI ENERGY INC.
INDIANA	GIBSON	2	PSI ENERGY INC.
INDIANA	GIBSON	3	PSI ENERGY INC.
INDIANA	GIBSON	4	PSI ENERGY INC.
INDIANA	RA GALLAGHER	1	PSI ENERGY INC.
INDIANA	RA GALLAGHER	2	PSI ENERGY INC.
INDIANA	RA GALLAGHER	3	PSI ENERGY INC.
INDIANA	RA GALLAGHER	4	PSI ENERGY INC.
INDIANA	FRANK E RATTS	1SG1	HOOSIER ENERGY REC.
INDIANA	FRANK E RATTS	2SG1	HOOSIER ENERGY REC.
INDIANA	WABASH RIVER	1	PSI ENERGY INC.
INDIANA	WABASH RIVER	2	PSI ENERGY INC.
INDIANA	WABASH RIVER	3	PSI ENERGY INC.
INDIANA	WABASH RIVER	5	PSI ENERGY INC.
IOWA	DES MOINES	11	IOWA PWR & LT CO.
IOWA	PRAIRIE CREEK	4	IOWA ELEC LT & PWR.
KANSAS	QUINDARO	2	KS CITY BD PUB UTIL.
KENTUCKY	COLEMAN	C1	BIG RIVERS ELEC CORP.
KENTUCKY	COLEMAN	C2	BIG RIVERS ELEC CORP.
KENTUCKY	COLEMAN	C3	BIG RIVERS ELEC CORP.
KENTUCKY	EW BROWN	1	KENTUCKY UTL CO.
KENTUCKY	GREEN RIVER	5	KENTUCKY UTL CO.
KENTUCKY	HMP&L STATION 2	H1	BIG RIVERS ELEC CORP.
KENTUCKY	HMP&L STATION 2	H2	BIG RIVERS ELEC CORP.
KENTUCKY	HL SPURLOCK	1	EAST KY PWR COOP.
KENTUCKY	JS COOPER	1	EAST KY PWR COOP.
KENTUCKY	JS COOPER	2	EAST KY PWR COOP.
MARYLAND	CHALK POINT	1	POTOMAC ELEC PWR CO.

TABLE 2.—PHASE I DRY BOTTOM-FIRED UNITS—Continued

State	Plant	Unit	Operator
MARYLAND	CHALK POINT	2	POTOMAC ELEC PWR CO.
MINNESOTA	HIGH BRIDGE	6	NORTHERN STATES PWR.
MISSISSIPPI	JACK WATSON	4	MISSISSIPPI PWR CO.
MISSISSIPPI	JACK WATSON	5	MISSISSIPPI PWR CO.
MISSOURI	JAMES RIVER	5	SPRINGFIELD UTL.
OHIO	CONESVILLE	3	COLUMBUS STHERN PWR.
OHIO	EDGEWATER	13	OHIO EDISON CO.
OHIO	MIAMI FORT [1]	5–1	CINCINNATI GAS&ELEC.
OHIO	MIAMI FORT [1]	5–2	CINCINNATI GAS&ELEC.
OHIO	PICWAY	9	COLUMBUS STHERN PWR.
OHIO	RE BURGER	7	OHIO EDISON CO.
OHIO	RE BURGER	8	OHIO EDISON CO.
OHIO	WH SAMMIS	5	OHIO EDISON CO.
OHIO	WH SAMMIS	6	OHIO EDISON CO.
PENNSYLVANIA	ARMSTRONG	1	WEST PENN POWER CO.
PENNSYLVANIA	ARMSTRONG	2	WEST PENN POWER CO.
PENNSYLVANIA	MARTINS CREEK	1	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	MARTINS CREEK	2	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	SHAWVILLE	1	PENNSYLVANIA ELEC CO.
PENNSYLVANIA	SHAWVILLE	2	PENNSYLVANIA ELEC CO.
PENNSYLVANIA	SUNBURY	3	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	SUNBURY	4	PENNSYLVANIA PWR & LT.
TENNESSEE	JOHNSONVILLE	7	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	8	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	9	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	10	TENNESSEE VAL AUTH.
WEST VIRGINIA	HARRISON	1	MONONGAHELA POWER CO.
WEST VIRGINIA	HARRISON	2	MONONGAHELA POWER CO.
WEST VIRGINIA	HARRISON	3	MONONGAHELA POWER CO.
WEST VIRGINIA	MITCHELL	1	OHIO POWER CO.
WEST VIRGINIA	MITCHELL	2	OHIO POWER CO.
WISCONSIN	JP PULLIAM	8	WISCONSIN PUB SER CO.
WISCONSIN	NORTH OAK CREEK [2]	1	WISCONSIN ELEC PWR.
WISCONSIN	NORTH OAK CREEK [2]	2	WISCONSIN ELEC PWR.
WISCONSIN	NORTH OAK CREEK [2]	3	WISCONSIN ELEC PWR.
WISCONSIN	NORTH OAK CREEK [2]	4	WISCONSIN ELEC PWR.
WISCONSIN	SOUTH OAK CREEK [2]	5	WISCONSIN ELEC PWR.
WISCONSIN	SOUTH OAK CREEK [2]	6	WISCONSIN ELEC PWR.

[1] Vertically fired boiler.
[2] Arch-fired boiler.

TABLE 3.—PHASE I CELL BURNER TECHNOLOGY UNITS

State	Plant	Unit	Operator
INDIANA	WARRICK	4	STHERN IND GAS & EL.
MICHIGAN	JH CAMPBELL	2	CONSUMERS POWER CO.
OHIO	AVON LAKE	12	CLEVELAND ELEC ILLUM.
OHIO	CARDINAL	1	CARDINAL OPERATING.
OHIO	CARDINAL	2	CARDINAL OPERATING.
OHIO	EASTLAKE	5	CLEVELAND ELEC ILLUM.
OHIO	GENRL JM GAVIN	1	OHIO POWER CO.
OHIO	GENRL JM GAVIN	2	OHIO POWER CO.
OHIO	MIAMI FORT	7	CINCINNATI GAS & EL.
OHIO	MUSKINGUM RIVER	5	OHIO POWER CO.
OHIO	WH SAMMIS	7	OHIO EDISON CO.
PENNSYLVANIA	HATFIELDS FERRY	1	WEST PENN POWER CO.
PENNSYLVANIA	HATFIELDS FERRY	2	WEST PENN POWER CO.
PENNSYLVANIA	HATFIELDS FERRY	3	WEST PENN POWER CO.
TENNESSEE	CUMBERLAND	1	TENNESSEE VAL AUTH.
TENNESSEE	CUMBERLAND	2	TENNESSEE VAL AUTH.
WEST VIRGINIA	FORT MARTIN	2	MONONGAHELA POWER CO.

Appendix B to Part 76—Procedures and Methods for Estimating Costs of Nitrogen Oxides Controls Applied to Group 1, Phase I Boilers

1. Purpose and Applicability

This technical appendix specifies the procedures, methods, and data that the Administrator will use in establishing ‘‘***the degree of reduction achievable through this retrofit application of the best system of continuous emission reduction, taking into account available technology, costs, and energy and environmental impacts; and which is comparable to the costs of nitrogen oxides controls set pursuant to subsection (b)(1) (of section 407 of the Act).’’ 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.

The Administrator will evaluate the capital cost (in dollars per kilowatt electrical ($/kW)), the operating and maintenance costs (in $/year), and the cost-effectiveness (in annualized $/ton NO_X removed) of installed low NO_X burner technology controls over a range of boiler sizes (as measured by the gross electrical capacity of the associated generator in megawatt electrical (MW)) and utilization rates (in percent gross nameplate capacity on an annual basis) to develop estimates of the average capital cost and cost-effectiveness for Group 1, Phase I boilers. The following units will be excluded from these determinations of the average capital cost and cost-effectiveness of NO_X controls set pursuant to subsection (b)(1) of section 407 of the Act: (1) Units employing an alternative technology, or only overfire air as applied to wall-fired boilers or only separated overfire air as applied to tangentially fired boilers, in lieu of low NO_X burner technology for reducing NO_X emissions; (2) units employing no controls, only controls installed before November 15, 1990, or only modifications to boiler operating parameters (e.g., burners out of service or fuel switching) for reducing NO_X emissions; and (3) units that have not achieved the applicable emission limitation.

2. Average Capital Cost for Low NO_X Burner Technology Applied to Group 1, Phase I Boilers

The Administrator will use the procedures, methods, and data specified in this section to estimate the average capital cost (in $/kW) of installed low NO_X burner technology applied to Group 1, Phase I boilers.

2.1 Using cost data submitted pursuant to the reporting requirements in section 4 below, boiler-specific actual or estimated actual capital costs will be determined for each unit in the population specified in section 1 above for assessing the costs of installed low NO_X burner technology. The scope of installed low NO_X burner technology costs will include the following capital costs for retrofit application: (1) For the burner portion—burners or air and coal nozzles, burner throat and waterwall modifications, and windbox modifications; and, where applicable, (2) for the combustion air staging portion—waterwall modifications or panels, windbox modifications, and ductwork, and (3) scope adders or supplemental equipment such as replacement or additional fans, dampers, or ignitors necessary for the proper operation of the low NO_X burner technology. Capital costs associated with boiler restoration or refurbishment such as replacement of air heaters, asbestos abatement, and recasing will not be included in the cost basis for installed low NO_X burner technology. The scope of installed low NO_X burner technology retrofit capital costs will include materials, construction and installation labor, engineering, and overhead costs.

2.2 Using gross nameplate capacity (in MW) for each unit as reported in the National Allowance Data Base (NADB), boiler-specific capital costs will be converted to a $/kW basis.

2.3 Capital cost curves ($/kW versus boiler size in MW) or equations for installed low NO_X burner technology retrofit costs will be developed for: (1) Dry bottom wall fired boilers (excluding units applying cell burner technology) and (2) tangentially fired boilers.

2.4 The capital cost curves or equations defined above will be used to develop weighted average cost estimates of installed low NO_X burner technology applied to Group 1, Phase I boilers. The weighting factor will be the unit gross nameplate generating capacity (in MW) as reported in the NADB.

3. Average Cost-Effectiveness for Low NO_X Burner Technology Applied to Group 1, Phase I Boilers

The Administrator will use the procedures, methods, and data specified in this section to estimate the average cost-effectiveness (in annualized $/ton NO_X removed) of installed low NO_X burner technology applied to Group 1, Phase I boilers.

3.1 Boiler-specific estimates of annual tons NO_X removed by the installed low NO_X burner technology will be determined for each unit in the population specified in section 1 above.

3.1.1 The baseline NO_X emission rate (in lb/mmBtu, annual average basis) will be estimated prior to retrofitting any low NO_X burner technology controls. For units that have installed and certified continuous emission monitoring systems for measuring the NO_X emission rate pursuant to part 75 of this chapter at least 120 days prior to the low NO_X burner technology retrofit, an estimate of the average annual uncontrolled NO_X emission rate will be developed using continuous emission monitoring data for the 120 days immediately before the low NO_X burner technology retrofit or another continuous 120-day or longer period as approved by the Administrator. (In cases where 120 days of certified and quality-assured continuous emission monitoring data are not available prior to the low NO_X burner technology retrofit, the Administrator may use continuous emission monitoring data over a shorter period or short-term test data to estimate the uncontrolled NO_X emission rate.) Continuous emission monitoring data or other emission rate measurements will be extrapolated to one year of unit operation.

3.1.2 The controlled NO_X emission rate (in lb/mmBtu, annual average basis) will be estimated after installation, shakedown, and/or optimization of all low NO_X burner technology controls have been completed and while the unit is complying with the applicable emission limitation (or alternative emission limitation). Continuous emission monitoring data submitted pursuant to part 75 of this chapter will be used for the 120 days immediately following installation and testing of the final low NO_X burner technology, provided the unit is complying with the applicable emission limitation (or alternative emission limitation), or another continuous 120-day or shorter period as approved by the Administrator. Continuous emission monitoring data will be extrapolated to one year of unit operation.

3.1.3 The NO_X emission reduction (in lb/mmBtu, annual average basis) achieved by the installed low NO_X burner technology will be estimated by subtracting the controlled NO_X emission rate defined in section 3.1.2 from the uncontrolled NO_X emission rate defined in section 3.1.1.

3.1.4 Annual estimates of the NO_X emission reduction achieved by the installed low NO_X burner technology will be converted to annual tons of NO_X removed by multiplying it by the annual heat input (in mmBtu). Unit heat input data submitted pursuant to part 75 of this chapter for calendar year 1994 or for the year immediately following installation and testing of the final low NO_X burner technology, will be used when such data are available prior to October 30, 1995. Such data will be adjusted to an annual basis whenever a nonrecurrent extended outage at the affected unit during the period has taken place.

3.2 The boiler-specific capital costs of installed low NO_X burner technology developed in section 2.1 will be annualized by multiplying them by a constant dollar capital recovery factor based on a 20-year economic life (e.g., 0.115).

3.3 Using cost data submitted pursuant to the reporting requirements in section 4, boiler-specific annual operating and maintenance cost increases (or decreases) will be determined for each unit in the population specified in section 1 above. The scope of the operating and maintenance costs (or savings) attributable to the installed low NO_X burner technology may, but not necessarily will, include incremental increases (or decreases) in: maintenance labor and materials costs, operating labor costs, operating fuel costs, and secondary air fan electricity costs.

3.4 The average annual cost-effectiveness of installed low NO_X burner technology applied to Group 1, Phase I boilers will be estimated as follows: (1) The annualized capital costs defined in section 3.2 and the annual operating and maintenance cost increases (or decreases) defined in section 3.3 will be summed for all units in the population specified in section 1; and (2) these annualized costs will be divided by the sum of the NO_X emission reductions (in tons/year) achieved by the units in the population specified in section 1.

4. Reporting Requirements

4.1 The following information is to be submitted by each designated representative of a Phase I affected unit subject to the reporting requirements of § 76.14(c):

4.1.1 Schedule and dates for baseline testing, installation, and performance testing of low NO_X burner technology.

4.1.2 Estimates of the annual average baseline NO_X emission rate, as specified in section 3.1.1, and the annual average controlled NO_X emission rate, as specified in section 3.1.2, including the supporting continuous emission monitoring or other test data.

4.1.3 Copies of pre-retrofit and post-retrofit performance test reports.

4.1.4 Detailed estimates of the capital costs based on actual contract bids for each component of the installed low NO_X burner technology including the items listed in section 2.1. Indicate number of bids solicited. Provide a copy of the actual agreement for the installed technology.

4.1.5 Detailed estimates of the capital costs of system replacements or upgrades such as coal pipe changes, fan replacements/upgrades, or mill replacements/upgrades undertaken as part of the low NO_X burner technology retrofit project.

4.1.6 Detailed breakdown of the actual costs of the completed low NO_X burner technology retrofit project where low NO_X burner technology costs (section 4.1.4) are disaggregated, if feasible, from system replacement or upgrade costs (section 4.1.5).

4.1.7 Description of the probable causes for significant differences between actual and estimated low NO_X burner technology retrofit project costs.

4.1.8 Detailed breakdown of the burner and, if applicable, combustion air staging system annual operating and maintenance costs for the items listed in section 3.3 before and after the installation, shakedown, and/or optimization of the installed low NO_X burner technology. Include estimates and a description of the probable causes of the incremental annual operating and maintenance costs (or savings) attributable to the installed low NO_X burner technology.

4.2 All capital cost estimates are to be broken down into materials costs, construction and installation labor costs, and engineering and overhead costs. All operating and maintenance costs are to be broken down into maintenance materials costs, maintenance labor costs, operating labor costs, and fan electricity costs. All capital and operating costs are to be reported in dollars with the year of expenditure or estimate specified for each component.

[FR Doc. 95–8742 Filed 4–12–95; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

43 CFR Public Land Order 7132

[AZ–930–1430–01; AR 06449]

Revocation of Public Land Order No. 1076; Arizona

AGENCY: Bureau of Land Management, Interior.

ACTION: Public Land Order.

SUMMARY: This order revokes a public land order which withdrew 240 acres of public land for use by the National Park Service in connection with the administration and maintenance of the Wupatki National Monument. The land was added to the Wupatki National Monument by Public Law 87–136, and the revocation is needed to clarify the records and give the National Park Service total jurisdiction. The land has been and will remain closed to surface entry and mining. This is a record clearing action only.

EFFECTIVE DATE: April 13, 1995.

FOR FURTHER INFORMATION CONTACT: John Mezes, BLM Arizona State Office, P.O. Box 16563, Phoenix, Arizona 85011, 602–650–0509.

By virtue of the authority vested in the Secretary of the Interior by Section 204 of the Federal Land Policy and Management Act of 1976, 43 U.S.C. 1714 (1988), it is ordered as follows:

1. Public Land Order No. 1076, which withdrew the following described public land, is hereby revoked in its entirety:

Gila and Salt River Meridian

T. 25 N., R. 8 E.,

Sec. 3, W½, that part lying west of the west right-of-way line of U.S. Highway 89 (consisting of lot 4, SW¼NW¼, NW¼SW¼, part of the westerly portions of lot 3, SE¼NW¼, and E½SW¼)

The area described contains 240 acres in Coconino County.

2. The land is located within the Wupatki National Monument and will remain closed to surface entry and mining.

Dated: April 4, 1995.

Bob Armstrong,

Assistant Secretary of the Interior.

[FR Doc. 95–9098 Filed 4–12–95; 8:45 am]

BILLING CODE 4310–32–P

43 CFR Public Land Order 7133

[OR–943–1430–01; GP5–038; OR–50706(WA)]

Withdrawal of National Forest System Lands for Five Seed Orchards; Washington

AGENCY: Bureau of Land Management, Interior.

ACTION: Public land order.

SUMMARY: This order withdraws 496.22 acres of National Forest System lands in the Colville and Kaniksu National Forests from mining for a period of 20 years for the Department of Agriculture, Forest Service, to protect the Brown