ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 72, 75, and 96

[FRL–6171–2]

RIN 2060–AH10

Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In accordance with the Clean Air Act (CAA), today's action is a final rule to require 22 States and the District of Columbia to submit State implementation plan (SIP) revisions to prohibit specified amounts of emissions of oxides of nitrogen (NO_X)—one of the precursors to ozone (smog) pollution—for the purpose of reducing NO_X and ozone transport across State boundaries in the eastern half of the United States.

Ground-level ozone has long been recognized, in both clinical and epidemiological research, to affect public health. There is a wide range of ozone-induced health effects, including decreased lung function (primarily in children active outdoors), increased respiratory symptoms (particularly in highly sensitive individuals), increased hospital admissions and emergency room visits for respiratory causes (among children and adults with pre-existing respiratory disease such as asthma), increased inflammation of the lung, and possible long-term damage to the lungs.

In today's action, EPA finds that sources and emitting activities in each of the 22 States and the District of Columbia (23 jurisdictions) emit NO_X in amounts that significantly contribute to nonattainment of the 1-hour and 8-hour ozone national ambient air quality standards (NAAQS), or will interfere with maintenance of the 8-hour NAAQS, in one or more downwind States. Further, by today's action, EPA is requiring each of the affected upwind jurisdictions (sometimes referred to as upwind States) to submit SIP revisions prohibiting those amounts of NO_X emissions which significantly contribute to downwind air quality problems. The reduction of those NO_X emissions will bring NO_X emissions in each of those States to within the resulting statewide NO_X emissions budget levels established in today's rule. The 23 jurisdictions are: Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin. These States will be able to choose any mix of pollution-reduction measures that will achieve the required reductions.

EFFECTIVE DATES: This rule is effective December 28, 1998. The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of December 28, 1998.

ADDRESSES: Dockets containing information relating to this rulemaking (Docket No. A–96–56 and Docket No. A–9–35) are available for public inspection at the Air and Radiation Docket and Information Center (6102), US Environmental Protection Agency, 401 M Street SW, room M–1500, Washington, DC 20460, telephone (202) 260–7548, between 8:00 a.m. and 4:00 p.m., Monday through Friday, excluding legal holidays. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: General questions concerning today's action should be addressed to Kimber S. Scavo, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD–15, Research Triangle Park, NC 27711, telephone (919) 541–3354; e-mail: scavo.kimber@epa.gov. Please refer to **SUPPLEMENTARY INFORMATION** below for a list of contacts for specific subjects described in today's action.

SUPPLEMENTARY INFORMATION:

Availability of Related Information

Documents related to the Ozone Transport Assessment Group (OTAG) are available on the Agency's Office of Air Quality Planning and Standards' (OAQPS) Technology Transfer Network (TTN) via the web at http://www.epa.gov/ttn/. If assistance is needed in accessing the system, call the help desk at (919) 541–5384 in Research Triangle Park, NC. Documents related to OTAG can be downloaded directly from OTAG's webpage at http://www.epa.gov/ttn/otag/. The OTAG's technical data are located at http://www.iceis.mcnc.org/OTAGDC. The notice of proposed rulemaking for this final action, the supplemental notice of proposed rulemaking, and associated documents are located at http://epa.gov/ttn/oarpg/otagsip.html. Information related to Sections II, Weight of Evidence Determination of Covered States, and IV, Air Quality Assessment, can be obtained in electronic form from the following EPA website: http://www.epa.gov/scram001/regmodcenter/t28.htm. Information related to Section III, Determination of Budgets, may be found on the following EPA website: http://www.epa.gov/capi. All information in electronic form may also be found on diskettes that have been placed in the docket to this rulemaking.

For Additional Information

For technical questions related to the air quality analyses, please contact Norm Possiel; Office of Air Quality Planning and Standards; Emissions, Monitoring, and Analysis Division; MD–14, Research Triangle Park, NC 27711, telephone (919) 541–5692. For legal questions, please contact Howard J. Hoffman, Office of General Counsel, 401 M Street SW, MC–2344, Washington, DC 20460, telephone (202) 260–5892. For questions concerning the statewide emissions budget revisions, please contact Laurel Schultz; Office of Air Quality Planning and Standards; Emissions, Monitoring, and Analysis Division; MD–14, Research Triangle Park, NC 27711, telephone (919) 541–5511. For questions concerning SIP reporting requirements, please contact Bill Johnson, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD–15, Research Triangle Park, NC 27711, telephone (919) 541–5245. For questions concerning the model cap-and-trade rule, please contact Rob Lacount, Office of Atmospheric Programs, Acid Rain Division, MC–6204J, 401 M Street SW, Washington, DC 20460, telephone (202) 564–9122. For questions concerning the regulatory cost analysis of electricity generating sources, please contact Ravi Srivastava, Office of Atmospheric Programs, Acid Rain Division, MC–6204J, 401 M Street SW, Washington DC 20460, telephone (202) 564–9093. For questions concerning the regulatory cost analysis of other stationary sources and questions concerning the Regulatory Impact Analysis (RIA), please contact Scott Mathias, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD–15, Research Triangle Park, NC 27711, telephone (919) 541–5310.

Outline

CFR Revisions and Additions

I. Background

A. Summary of Rulemaking and Affected States

By notice of proposed rulemaking (NPR, proposal, or ''proposed SIP call'') (62 FR 60318, November 7, 1997) and by supplemental notice (SNPR or supplemental proposal) (63 FR 25902, May 11, 1998), EPA proposed to find that NO_X emissions from sources and emitting activities (sources) in 23 jurisdictions (hereinafter also referred to as States) will significantly contribute to nonattainment of the 1-hour and 8-hour ozone NAAQS, or will interfere with maintenance of the 8-hour NAAQS, in one or more downwind States throughout the Eastern United States. The EPA based these proposals on data generated by OTAG, public comments, and other relevant information. Today's final action confirms that proposed finding. It also requires, under CAA section 110(a)(1) and 110(k)(5), that the 23 jurisdictions adopt and submit SIP revisions that, in order to assure that their SIPs meet the requirements of section 110(a)(2)(D)(i)(I), contain provisions adequate to prohibit sources in those States from emitting NO_X in amounts that ''contribute significantly to nonattainment in, or interfere with maintenance by,'' a downwind State. The 23 jurisdictions are: Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

Each of these States and the District of Columbia is required to adopt and submit by September 30, 1999, a SIP revision. The SIP revision must contain measures that will assure that sources in the State reduce their NO_X emissions sufficiently to eliminate the amounts of NO_X emissions that contribute significantly to nonattainment, or that interfere with maintenance, downwind. By eliminating these amounts of NO_X emissions, the control measures will assure that the remaining NO_X emissions will meet the level identified in today's rule as the State's NO_X emissions budget. For simplicity, this final rule may refer to the amounts that such SIP provisions must prohibit in order to meet the statute as the ''significant amounts'' of NO_X emissions. After prohibiting these significant amounts of NO_X, the remaining amounts emitted by sources in the covered States will not ''significantly contribute to nonattainment, or interfere with maintenance by,'' a downwind State, under section 110(a)(2)(D)(i)(I). Section II.C, Weight-of-Evidence Determination of Covered States, describes how EPA determined which States include sources that emit NO_X in amounts of concern (the ''covered'' States), and Sections II.D, Cost Effectiveness of Emissions Reductions; II.E, Comparison of Upwind and Downwind Costs; and III, Determination of Budgets, describe how EPA determined the significant amounts of emissions and the resulting statewide emissions budgets for the States identified above. Section IV, Air Quality Assessment, discusses air quality analyses conducted by EPA which help confirm the decisions and requirements set forth in this rulemaking. Section V, NO_X Control Implementation and Budget Achievement Dates, primarily discusses the dates by which (1) the States must submit SIP revisions in response to today's action, (2) the sources must implement the measures the States choose for the purpose of prohibiting the significant amounts of NO_X, and (3) the States are projected to achieve the budget levels. Section VI, SIP Criteria and Emissions Reporting Requirements, describes the SIP requirements themselves.

The SIP requirements permit each State to determine what measures to adopt to prohibit the significant amounts and hence meet the necessary emissions budget. Consistent with OTAG's recommendations to achieve

NO_X emissions decreases primarily from large stationary sources in a trading program, EPA encourages States to consider electric utility and large boiler controls under a cap-and-trade program as a cost-effective strategy. The recommended cap-and-trade program is described in more detail in Section VII, NO_X Budget Trading Program. The EPA also recognizes that promotion of energy efficiency can contribute to a cost-effective strategy. In Section VIII, Interaction with Title IV NO_X rule, EPA explains that it is not adopting proposed revisions to the title IV NO_X rule concerning the relationship between this rulemaking and the title IV NO_X rule. The remaining parts of today's action include Section IX, Non-Ozone Benefits of NO_X Reductions, and Section X, Administrative Requirements.

The EPA also conducted a RIA which is available in the docket to this rulemaking as a technical support document (TSD), entitled ''Regulatory Impact Analysis for the Regional NO_X SIP Call'' (docket no. VI–B–09). A detailed explanation of how EPA calculated the budgets is also available as a TSD entitled ''Development of Modeling Inventory and Budgets for the Regional NO_X SIP Call'' (docket no. VI–B–10). These two TSDs have been revised for the final rulemaking. A detailed explanation of the air quality modeling analyses is also available, entitled ''Air Quality Modeling Technical Support Document for the Regional NO_X SIP Call'' (docket no. VI–B–11) for this final rulemaking. This preamble for today's notice responds to some of the comments, but another document, entitled ''Response to Significant Comments on the Finding of Significant Contribution and Rulemaking for Certain States in the OTAG Region for Purposes of Reducing Regional Transport of Ozone,'' is included in the docket (docket no. VI–C–01).

B. General Factual Background

In today's action, EPA takes a significant step toward reducing ozone in the eastern half of the country. Ground-level ozone, the main harmful ingredient in smog, is produced in complex chemical reactions when its precursors, volatile organic compounds (VOC) and NO_X, react in the presence of sunlight. The chemical reactions that create ozone take place while the pollutants are being blown through the air by the wind, which means that ozone can be more severe many miles away from the source of emissions than it is at the source.

The science of ozone formation, transport, and accumulation is complex. Ozone is produced and destroyed in a cyclical set of chemical reactions involving NO_X, VOC and sunlight. Emissions of NO_X and VOC are necessary for the formation of ozone in the lower atmosphere. In part of the cycle of reactions, ozone concentrations in an area can be lowered by the reaction of nitric oxide with ozone, forming nitrogen dioxide; as the air moves downwind and the cycle continues, the nitrogen dioxide forms additional ozone. The importance of this reaction depends, in part, on the relative concentrations of NO_X, VOC and ozone, all of which change with time and location.

At ground level, ozone can cause a variety of ill effects to human health, crops and trees. Specifically, ground-level ozone has been shown in clinical and/or epidemiologial studies to have the following health effects:

- Decreased lung function, primarily in children active outdoors
- Increased respiratory symptoms, particularly in highly sensitive individuals
- Hospital admissions and emergency room visits for respiratory causes among children and adults with pre-existing respiratory disease such as asthma
- Inflammation of the lung
- Possible long-term damage to the lungs or even premature death.

The new 8-hour primary ambient air quality standard (62 FR 38856, July 18, 1997) will provide increased protection to the public from these health effects.

Each year, ground-level ozone above background is also responsible for significant agricultural crop yield losses. Ozone also causes noticeable foliar damage in many crops, trees, and ornamental plants (i.e., grass, flowers, shrubs, and trees) and causes reduced growth in plants. Studies indicate that current ambient levels of ozone are responsible for damage to forests and ecosystems (including habitat for native animal species).

As part of the efforts to reduce harmful levels of smog, EPA, today, is establishing a requirement for certain States to revise their SIPs in order to implement the necessary regional-scale reductions in NO_X emissions, and, thereby, reduce transported NO_X and ozone. Since air pollution travels across county and State lines, it is essential for State governments and air pollution control agencies to cooperate to solve the problem.

Currently, the following areas, impacted by the 23 jurisdictions that are the subject of today's rulemaking, are designated nonattainment areas for ozone under the 1-hour NAAQS:

Atlanta, GA
Baltimore, MD
Birmingham, AL
Boston-Lawrence-Worcester (eastern MA), MA–NH
Chicago-Gary-Lake County, IL–IN
Cincinnati-Hamilton, OH–KY
Door County, WI
Greater Connecticut
Kent & Queen Anne's Counties, MD
Lancaster, PA
Louisville, KY–IN
Manitowoc County, WI
Milwaukee-Racine, WI
Muskegon, MI
New York-Northern New Jersey-Long Island, NY–NJ–CT
Philadelphia-Wilmington-Trenton, PA–NJ–DE–MD
Pittsburgh-Beaver Valley, PA
Portland, ME
Portsmouth-Dover-Rochester, NH
Providence (All RI), RI
St. Louis, MO–IL
Springfield (western MA), MA
Washington, DC–MD–VA

These areas include many of the major urban centers in the eastern half of the Nation. The combined population for these areas is approximately 61.5 million. As described elsewhere, the reductions called for in today's action will reduce ozone levels throughout these areas.

Many more areas currently violate the 8-hour NAAQS. The EPA estimates that a total population of approximately 73 million in the 23 jurisdictions live in counties for which air quality is monitored to be in violation of that NAAQS. The reductions called for in today's action will reduce ozone levels throughout these areas as well.

Moreover, as discussed below, many of these areas are expected to be classified as ''transitional,'' which means, in most cases, that they are expected to come into attainment solely as a result of the reductions required by today's action. Thus, for those who live in these areas, the reductions required under today's action, in-and-of-themselves, are expected to mean the difference between unhealthful ozone levels and acceptable ozone levels.

Please note that EPA will not designate ozone nonattainment areas for the 8-hour NAAQS until 2000, and these designations will be based on the data that are most recently available at that time.

C. Statutory and Regulatory Background

1. CAA Provisions

a. 1970 and 1977 CAA Amendments. For almost 30 years, Congress has focused major efforts on curbing ground-level ozone. In 1970, Congress amended the CAA to require, in title I, that EPA issue, and periodically review and if necessary revise, NAAQS for ubiquitous air pollutants (sections 108 and 109). Congress required the States to submit SIPs to attain and maintain those NAAQS, and Congress included, in section 110, a list of minimum requirements that SIPs must meet. Congress anticipated that areas would attain the NAAQS by 1975.

In 1977, Congress amended the CAA by providing, among other things, additional time for areas that were not attaining the ozone NAAQS to do so, as well as by imposing specific SIP requirements for those nonattainment areas. These provisions first required the designation of areas as attainment, nonattainment, or unclassifiable, under section 107; and then required that SIPs for ozone nonattainment areas include the additional provisions set out in part D of title I, as well as demonstrations of attainment of the ozone NAAQS by either 1982 or 1987 (section 172).

In addition, the 1977 Amendments included two provisions focused on interstate transport of air pollutants: the predecessor to current section 110(a)(2)(D), which requires SIPs for all areas to constrain emissions with certain adverse downwind effects; and section 126, which, in general, authorizes a downwind State to petition EPA to impose limits directly on upwind sources found to adversely affect that State. Section 110(a)(2)(D), which is key to the present action, is described in more detail below.

b. 1990 CAA Amendments. In 1990, Congress amended the CAA to better address, among other things, continued nonattainment of the 1-hour ozone NAAQS; the requirements that would apply if EPA revised the 1-hour standard; and transport of air pollutants across State boundaries (Pub. L. 101–549, Nov. 15, 1990, 104 Stat. 2399, 42 U.S.C., 7401–7671q). Numerous provisions added, or revised, by the 1990 Amendments are relevant to today's proposal.

(1) 1-Hour Ozone NAAQS. In the 1990 Amendments, Congress required the States and EPA to review and, if necessary, revise the designation of areas as attainment, nonattainment, and unclassifiable under the ozone NAAQS in effect at that time, which was the 1-hour standard (section 107(d)(4)). Areas designated as nonattainment were divided into, primarily, five classifications based on air quality design values (section 181(a)(1)). Each classification carries specific requirements, including new attainment dates (sections 181–182). In increasing severity of the air quality problem, these classifications are marginal, moderate, serious, severe and extreme. The OTAG region includes nonattainment areas of all classifications except extreme.

As amended in 1990, the CAA requires States containing ozone nonattainment areas classified as moderate or above to submit several SIP revisions at various times. One set of SIP revisions included specified control measures, such as reasonably available control technology (RACT) for existing VOC and NO_X sources (section 182(b)(2), 182(f)). In addition, the CAA requires the reduction of VOC in the amount of 15 percent by 1996 from a 1990 baseline (section 182(b)(1)). Further, for nonattainment areas classified as serious and above, the CAA requires the reduction of VOC or NO_X emissions in the amount of 9 percent over each 3-year period from 1996 through the attainment date (the rate-of-progress (ROP) SIP submittals), under section 182(c)(2)(B). In addition, the CAA requires a demonstration of attainment, including air quality modeling, for the nonattainment area (the attainment demonstration), as well as SIP measures containing any additional reductions that may be necessary to attain by the applicable attainment date (section 182(c)-(e)). The CAA established November 15, 1994 as the required date for the ROP and attainment demonstration SIP submittals for areas classified as serious and above.[1]

(2) *Revised NAAQS.* Section 109(d) of the CAA requires periodic review and, if appropriate, revision of the NAAQS. As amended in 1990, the CAA further requires EPA to designate areas as attainment, nonattainment, and unclassifiable under a revised NAAQS (section 107(d)(1); section 6103, Pub. L. 105–178). The CAA authorizes EPA to classify areas that are designated nonattainment under the new NAAQS and to establish for those areas attainment dates that are as expeditiously as practicable, but not to exceed 10 years from the date of designation (section 172(a)).

(3) General Requirements. The CAA continues, in revised form, certain requirements, dating from the 1970 Amendments, which pertain to all areas, regardless of their designation. All areas are required to submit SIPs within certain timeframes (section 110(a)(1)), and those SIPs must include specified provisions, under section 110(a)(2). In addition, SIPs for nonattainment areas are generally required to include additional specified control requirements, as well as controls providing for attainment of any revised NAAQS and periodic reductions providing ''reasonable further progress'' in the interim (section 172(c)).

(4) Provisions Concerning Transport of Ozone and Its Precursors. The 1990 Amendments reflect general awareness by Congress that ozone is a regional, and not merely a local, problem. As described above, ozone and its precursors may be transported long distances across State lines to combine with ozone and precursors downwind, thereby exacerbating the ozone problems downwind. The phenomenon of ozone transport was not generally recognized until relatively recently. Yet, ozone transport is a major reason for the persistence of the ozone problem, notwithstanding the imposition of numerous controls, both Federal and State, across the country.

Section 110(a)(2)(D) provides one of the most important tools for addressing the problem of transport. This provision, which applies by its terms to all SIPs for each pollutant covered by a NAAQS, and for all areas regardless of their attainment designation, provides that a SIP must contain adequate provisions prohibiting its sources from emitting air pollutants in amounts that will contribute significantly to nonattainment, or interfere with maintenance, in one or more downwind States.

Section 110(k)(5) authorizes EPA to find that a SIP is substantially inadequate to meet any CAA requirement. If EPA makes such a finding, it must require the State to submit, within a specified period, a SIP revision to correct the inadequacy.

The CAA further addresses interstate transport of pollution in section 126, which Congress revised slightly in 1990. Subsection (b) of that provision authorizes each State (or political subdivision) to petition EPA for a finding designed to protect that entity from upwind sources of air pollutants.[2]

In addition, the 1990 Amendments added section 184, which delineates a multistate ozone transport region (OTR) in the Northeast, requires specific additional controls for all areas (not only nonattainment areas) in that region, and establishes the Ozone Transport Commission (OTC) for the purpose of recommending to EPA regionwide controls affecting all areas in that region. At the same time, Congress added section 176A, which authorizes

[1] For moderate ozone nonattainment areas, the attainment demonstration was due November 15, 1993 (section 182(b)(1)(A)), except that if the State elected to conduct an urban airshed model, EPA allowed an extension to November 15, 1994.

[2] In addition, section 115 authorizes EPA to require a SIP revision when one or more sources within a State ''cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare in a foreign country.''

the formation of transport regions for other pollutants and in other parts of the country.

2. Regulatory Structure

a. March 2, 1995 Policy. Notwithstanding significant efforts, the States generally were not able to meet the November 15, 1994 statutory deadline for the attainment demonstration and ROP SIP submissions required under section 182(c). The major reason for this failure was that at that time, States with downwind nonattainment areas were not able to address transport from upwind areas. As a result, in a memorandum from Mary D. Nichols, Assistant Administrator for Air and Radiation, dated March 2, 1995, entitled ''Ozone Attainment Demonstrations,'' (March 2, 1995 Memorandum or the Memorandum), EPA recognized the efforts made by States and the remaining difficulties in making the ROP and attainment demonstration submittals. The EPA recognized that development of the necessary technical information, as well as the control measures necessary to achieve the large level of reductions likely to be required, had been particularly difficult for the States affected by ozone transport.

Accordingly, as an administrative remedial matter, the Memorandum indicated that EPA would establish new timeframes for SIP submittals. The Memorandum indicated that EPA would divide the required SIP submittals into two phases. Phase I generally consisted of (i) SIP measures providing for ROP reductions due by the end of 1999, (ii) an enforceable SIP commitment to submit any remaining required ROP reductions on a specified schedule after 1996, and (iii) an enforceable SIP commitment to submit the additional SIP measures needed for attainment. Phase II consists of the remaining submittals, beginning in 1997.

The Phase II submittals primarily consisted of the remaining ROP SIP measures, the attainment demonstration and additional rules needed to attain, and any regional controls needed for attainment by all areas in the region. The March 2, 1995 Memorandum indicated that the attainment demonstration, target calculations for the post-1999 ROP milestones, and identification of rules needed to attain and for post-1999 ROP were due in mid-1997. To allow time for States to incorporate the results of the OTAG modeling into their local plans, EPA extended the mid-1997 submittal date to April 1998.[3]

b. OTAG. In addition, the March 2, 1995 Memorandum called for an assessment of the ozone transport phenomenon. The Environmental Council of the States (ECOS) had recommended formation of a national work group to allow for a thoughtful assessment and development of consensus solutions to the problem. The OTAG was a partnership between EPA, the 37 easternmost States and the District of Columbia, industry representatives, and environmental groups. The OTAG's air quality modeling and recommendations formed the basis for today's action.

c. EPA's Transport SIP Call Regulatory Efforts. Shortly after OTAG began its work, EPA began to indicate that it intended to issue a SIP call to require States to implement the reductions necessary to address the ozone transport problem. On January 10, 1997 (62 FR 1420), EPA published a notice of intent that articulated this goal and indicated that before taking final action, EPA would carefully consider the technical work and any recommendations of OTAG. The EPA published the NPR for the NO_X SIP call by notice dated November 7, 1997 (62 FR 60319). The NPR proposed to make a finding of significant contribution due to transported NO_X emissions to nonattainment or maintenance problems downwind and to assign NO_X emissions budgets for 23 jurisdictions. The EPA published a supplemental notice of proposed rulemaking (SNPR) by notice dated May 11, 1998 (63 FR 25902) which proposed a model NO_X budget trading program and State reporting requirements and provided the air quality analyses of the proposed statewide NO_X emissions budgets. The EPA received approximately 700 comments on these proposals. The comment periods are described in Section I.F, Discussion of Comment Period and Availability of Key Information. Throughout the course of the rulemaking, EPA has added information to the docket. By notice dated August 24, 1998 (63 FR 45032), EPA published a notice of availability listing the additional documents placed in the docket.

d. Revision of the Ozone NAAQS. On July 18, 1997 (62 FR 38856), EPA issued its final action to revise the NAAQS for ozone. The EPA's decision to revise the standard was based on the Agency's review of the available scientific evidence linking exposures to ambient ozone to adverse health and welfare effects at levels allowed by the pre-existing 1-hour ozone standards. The 1-hour primary standard was replaced by an 8-hour standard at a level of 0.08 parts per million (ppm), with a form based on the 3-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration measured at each monitor within an area. The new primary standard will provide increased protection to the public, especially children and other at-risk populations, against a wide range of ozone-induced health effects. Health effects are described in paragraph I.B, General Factual Background. The EPA retained the applicability of the 1-hour NAAQS for existing nonattainment areas until such time as EPA determines that an area has attained the 1-hour NAAQS (40 CFR 50.9(b)).

The pre-existing 1-hour secondary ozone standard was replaced by an 8-hour standard identical to the new primary standard. The new secondary standard will provide increased protection to the public welfare against ozone-induced effects on vegetation.

D. Section 126 Petitions

In a separate rulemaking, EPA is proposing action on petitions submitted by eight northeastern States under section 126 of the CAA. Each petition specifically requests that EPA make a finding that NO_X emissions from certain major stationary sources significantly contribute to ozone nonattainment problems in the petitioning State. The eight States are Connecticut, Massachusetts, Maine, New Hampshire, New York, Pennsylvania, Rhode Island, and Vermont.

Both the NO_X SIP call and the section 126 petitions are designed to address ozone transport through reductions in upwind NO_X emissions. However, the EPA's response to the section 126 petitions differs from EPA's action in the NO_X SIP call rulemaking in several ways. In today's NO_X SIP call, EPA is determining that certain States are or will be significantly contributing to nonattainment or maintenance problems in downwind States. The EPA is requiring the upwind States to submit SIP provisions to reduce the amounts of each State's NO_X emissions that significantly contribute to downwind air quality problems. The States will have the discretion to select the mix of control measures to achieve the necessary reductions. By contrast, under section 126, if findings of significant contribution are made for any sources identified in the petitions, EPA would determine the necessary emissions

[3] Guidance for Implementing the 1-hour Ozone and Pre-Existing PM10 NAAQS, Memorandum from Richard D. Wilson, dated December 29, 1997.

limits to address the amount of significant contribution and would directly regulate the sources. A section 126 remedy would apply only to sources in States named in the petitions.

Based on the view that the SIP call and section 126 petitions are both designed to achieve the same goal, several commenters urged EPA to coordinate the two actions to the maximum extent possible. The EPA agrees that the two actions are closely related and, therefore, should be coordinated. This will help provide certainty for State and business planning requirements. In addition, this coordination can help to facilitate a trading program among sources in SIP call States that choose to participate in the NO_X trading program, and any section 126 sources that would be subject to a Federal NO_X trading program.

The section 126 provisions require that any control remedy be implemented within 3 years from the date of the finding that major sources or a group of stationary sources emit or would emit in violation of the relevant prohibition in section 110(a)(2)(D). Under EPA's anticipated rulemaking schedule [4] on the petitions, the compliance date for sources for which EPA makes such a finding could be April 30, 2002; November 30, 2002; or May 1, 2003. Several commenters expressed concern that the compliance deadline under section 126 was driving EPA's decision on the compliance deadline for the NO_X SIP call. Therefore, they believed that no changes would be made in the proposed NO_X SIP call deadline in response to comments.

While EPA believes it is advantageous to coordinate the section 126 and NO_X SIP call actions, EPA disagrees that this constrains EPA from being responsive to public comments and considering alternative compliance dates. See discussion below in Section V, NO_X Control Implementation and Budget Attainment Dates.

In the NO_X SIP call NPR, EPA proposed that States be required to submit SIPs within 12 months of the final SIP call. One commenter asserted that the timing and terms of the rulemaking schedule for the section 126 petitions precludes EPA from considering public comments advocating different SIP due dates for the NO_X SIP call. The section 126 rulemaking schedule provides several options. One option would allow findings on the petitions to be deferred pending certain actions by the States and EPA on State submittals in response to the NO_X SIP call. The premise for the specified schedule is that the SIP due date would be September 30, 1999 (i.e., roughly 12 months from signature of the notice on the final NO_X SIP call). As discussed below in Section VI, SIP Revision Criteria and Schedule, EPA continues to believe 12 months is an appropriate timeframe. However, had EPA determined that a longer timeframe for SIP submittal was warranted, the section 126 rulemaking schedule would not have restricted EPA from establishing a later due date.

One commenter supported the section 126 rulemaking schedule because they thought it had the effect of using the SIP process rather than the source-based petitions in that it provides an option of deferring section 126 findings if EPA approves a State's NO_X SIP. Another commenter thought that the conditions for deferring section 126 findings were too stringent, and, therefore, section 126 would inevitably be triggered prior to approval of any SIP provisions. This issue is discussed in detail in Section II.A.2.c. in the NPR EPA just issued on the section 126 petitions, which appears in the docket.

E. OTAG

As discussed in the proposed SIP call, OTAG completed the most comprehensive analyses of ozone transport ever conducted. The EPA participated extensively in this process. The EPA believes that the OTAG process was successful and generated much useful technical and modeling information on regional ozone transport. This information provided EPA with the foundation for this rulemaking.

The EPA received numerous comments regarding the relationship between the OTAG recommendations and EPA's proposed SIP call. Some commenters asserted that the Agency's proposal was inconsistent with the OTAG recommendations, while others believed that EPA used the information and recommendations from OTAG appropriately. Primarily, commenters stated that OTAG recommended a range of controls for utility sources instead of a uniform level of control for all of the included States.

The OTAG did recommend consideration of a range of controls, and although it did not specifically recommend uniform controls across a broad region, such a control scheme is within the range of its recommendation. The EPA's action today is based on its consideration of OTAG's recommendations, as well as information resulting from EPA's additional work, and extensive public input generated through notice-and-comment rulemaking. The EPA continues to believe, for reasons explained in Section III.F.1, Uniform vs. Regional Controls, that requiring NO_X emissions reductions across the region in amounts achievable by uniform controls is a reasonable, cost-effective step to take at this time to mitigate ozone nonattainment in downwind States for both the 1-hour and 8-hour standards.

Commenters also stated that EPA applied an electric utility control level that was more stringent than the upper limit of the OTAG range of utility controls. The OTAG recommended a range of utility controls that falls between specific CAA-required controls and the less stringent of 85 percent reduction from the 1990 rate (lb/mmBtu), or 0.15 lb/mmBtu. In determining the appropriate level of emissions reductions, EPA considered what levels of NO_X reductions could be obtained by applying, to various source sectors, controls that are among the most cost effective and feasible with today's proven pollution control technologies. The EPA chose emissions reductions that are equivalent to an emission limit from utilities of 0.15 lb/mmBtu. The EPA acknowledges that this level may be more protective than the most protective level contained in the OTAG recommendation in some cases, but, as discussed below in Section IV, Air Quality Assessment, EPA believes that it provides the most improvement in air quality while staying within the bounds of the most highly cost-effective technology available. (Cost effectiveness is discussed in Section II.D.) In addition, by relying on actual 1995–1996 continuous emission monitoring data, rather than relying on estimated 1990 emission data, this approach provides a more accurate way of determining the States' budgets since it minimizes any chances of over-or under-estimation of emissions.

Commenters asserted that OTAG recommended 12 months for additional modeling—especially subregional modeling—before promulgating the SIP call; and these commenters expressed concern that EPA did not provide this amount of time following publication of the NPR. As discussed in more detail in Section I.F, Discussion of Comment Period and Availability of Key

[4] The eight northeastern States that filed section 126 petitions also filed suit in the District Court for the Southern District of New York, to compel EPA to take action on those petitions within prescribed periods. *State of Connecticut* v. *Browner*, No. 98–1376 (S.D.N.Y., filed Feb. 25, 1998). The EPA and the eight northeastern States jointly filed a motion to enter a consent order prescribing certain dates for EPA action.

Information, the Agency ultimately provided approximately 1 year from the conclusion of OTAG for States and other members of the public to complete and submit subregional and other types of modeling. The EPA has considered this additional modeling in finalizing today's rule.

Some commenters stated that the goal of OTAG was to address attainment of the ozone NAAQS. This is incorrect. The OTAG's goal was to reduce ozone transport, which is one of the steps necessary to enable attainment; the goal was not to recommend an overall strategy that would yield attainment through regional measures alone. The OTAG articulated its overall goal as follows:

> * * * identify and recommend a strategy to reduce transported ozone and its precursors which, in combination with other measures, will enable attainment and maintenance of the national ambient ozone standard in the OTAG region. A number of criteria will be used to select the strategy including, but not limited to, cost effectiveness, feasibility, and impacts on ozone levels.[5]

It is also EPA's goal to ensure that sufficient regional reductions are achieved to mitigate ozone transport in the eastern half of the United States and thus, in conjunction with local controls, enable nonattainment areas to attain and maintain the ozone NAAQS.

Commenters indicated that OTAG focused only on the 1-hour standard nonattainment problem and did not assess compliance implications of the 8-hour standard. For this reason, according to commenters, EPA should not base today's action on the nonattainment of the 8-hour NAAQS. It is true that OTAG was established to address transport issues associated with meeting the 1-hour standard. The EPA did not promulgate the 8-hour standard until shortly after OTAG concluded; thus, OTAG did not recommend strategies to address the 8-hour NAAQS. However, because EPA had proposed an 8-hour standard, OTAG did examine the impacts of different strategies on 8-hour average ozone predictions.

In light of OTAG's work and additional information, EPA is able to assess ozone transport as it relates to the 8-hour NAAQS and to set forth requirements as necessary to address the 8-hour standard in this rulemaking. Ozone transport causes problems for downwind areas under either the 1-hour or 8-hour standard. The regional reductions of NO_X that will be achieved through this SIP call for the 1-hour NAAQS are key components for meeting the new 8-hour ozone standard in a cost-effective manner. Therefore, EPA believes that the OTAG recommendations for how to address ozone transport are valid for both NAAQS.

Several commenters urged EPA to adopt and implement all Federal measures identified in the OTAG recommendations.[6] The Agency is committed to continue implementing national control measures for NO_X, as recommended by OTAG. In addition, EPA has adopted the following national measures for purposes of reducing VOC: architectural and industrial maintenance coatings, consumer/commercial products, and autobody refinishing. The EPA has made no decisions regarding further VOC reductions beyond the reductions specified as phase I in the OTAG recommendations.[7]

Other more specific comments concerning the OTAG recommendations will be addressed throughout this rulemaking as the issues are discussed.

F. Discussion of Comment Period and Availability of Key Information

The EPA received numerous comments concerning the adequacy of the comment period for the November 7, 1997 NPR and May 11, 1998 SNPR. Some commenters remarked that the comment period for the NPR should be extended to allow for development and review of technical information, including inventory data, growth factors, and the resulting budget. Commenters stated that the additional time was particularly necessary for subregional air quality modeling, which is modeling designed to isolate the impacts of emissions from a particular State or group of States on downwind areas. Many specifically requested an additional 120 days, and one requested an additional 9 months. Some commenters indicated that EPA did not incorporate their comments from the NPR into the SNPR. Other commenters insisted that key information supporting the rule is not publicly available. The EPA also received comments that additional public hearings should be held in other locations of the OTAG region.

1. Request for Extension of the Comment Period

The EPA allowed a 120-day public comment period for the November 7, 1997 NPR, which closed on March 9, 1998. By notice (63 FR 17349, April 9, 1998), EPA reopened the comment period for members of the public to submit additional modeling analyses, as well as comments concerning the implications that any additional modeling may have for the State NOx budgets under consideration in the November 7, 1997 proposal. The comment period was reopened through the end of the comment period on the SNPR. The SNPR, which was published on May 11, 1998, allowed a comment period until June 25, 1998. Thus, for most issues addressed in the NPR, including air quality modeling issues, commenters received an almost 8-month formal comment period. Indeed, many commenters had access to the NPR immediately after October 10, 1997, when it was signed and posted on an EPA website. The Agency also received a number of comments after June 25, 1998, which were also reviewed and considered in developing the final rule.

The EPA believes this additional opportunity for the public to submit comments was reasonable. After March 9, 1998—the initial date for close of the comment period on the NPR—EPA received numerous comments on various issues raised in the NPR, including air quality issues. Many of these comments were extensive, which indicates that commenters received adequate time.

With respect to the concern that EPA did not incorporate comments received on the NPR into the SNPR, it would not have been practical for EPA to incorporate comments received on the NPR into the SNPR because the SNPR was completed soon after the close of the comment period for the NPR. In general, the SNPR addressed different aspects of the rule than the NPR, and one of the purposes of the SNPR was to take comment on several new issues, as noted above. The EPA has addressed comments on both the NPR and SNPR in today's action.

The major issues raised in the comments are responded to throughout the preamble of this final rule. A comprehensive summary of all significant comments, along with EPA's response to the comments which have not been responded to in the preamble (Response to Comments), can be found in the docket for this rulemaking (Docket No. A–96–56).

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[5] Ozone Transport Assessment Group Policy Paper approved by the Policy Group on December 4, 1995.

[6] The OTAG recommendations are located in Appendix B of the November 7, 1997 NPR (62 FR 60376).

[7] Letter to the Honorable Ken Calvert, Chairman, Subcommittee on Energy and Environment, U.S. House of Representatives, from Robert D. Brenner, Acting Deputy Assistant Administrator for Air and Radiation, U.S. EPA, June 26, 1998, transmitting EPA's responses to questions following the May 20, 1998 congressional hearing on EPA's proposed rule on paints and coatings.

2. Request for Time to Conduct Additional Modeling

The OTAG Policy Group, at its June 3, 1997 meeting, recommended that States have the opportunity to conduct additional local and subregional modeling and air quality analyses, as well as to develop and propose appropriate levels and timing of controls. The EPA received numerous comments related to OTAG's recommendation. The commenters requested that the Agency give States more time to conduct this additional modeling so that EPA could more accurately assess each State's contribution to downwind nonattainment.

The EPA signed the NPR on October 10, 1997, and posted it on a website at that time, although it was not published in the **Federal Register** until November 7, 1997. As noted above, EPA reopened the comment period through June 25, 1998 for submittal of additional air quality modeling runs. In effect, this has extended the amount of time for modeling analyses to over a year from the date OTAG submitted its recommendations, and to over 8 months from the signature date for the NPR. By the close of the comment period on June 25, 1998, EPA had received numerous comments containing new and extensive air quality modeling studies. Accordingly, EPA believes that commenters received adequate time.

3. Availability of Key Information

A number of commenters asserted that EPA failed to make publicly available key information, such as modeling and emissions inventory data. Specifically, commenters stated that they did not have access to the emissions data on which EPA based the air quality modeling for the NPR. In addition, according to some commenters, several models used by EPA and OTAG are proprietary models and have not been generally available to the public.

In Section III.A.2, Availability, the Agency discusses the availability of emissions inventory data to the public.

The OTAG and EPA conducted air quality modeling runs to determine the level of contribution from emissions in upwind areas to ozone nonattainment in downwind areas. Some of this modeling employed UAM–V.[8] The UAM–V has generally been available to the public for the purpose of analyzing information relevant to today's rulemaking. State and local agencies, as well as utility companies and other stakeholders, have had access to licenses to use UAM–V.

Commenters objected that they were obliged either to purchase licenses for use of the UAM–V model or to employ as a contractor the model owner, and that these financial constraints restricted their access to the model. Because this model has, in general, been privately developed, EPA believes that reasonable fees for its use should be expected. The EPA did not receive information indicating that the associated expenses were other than reasonable. To the extent that commenters experienced delays in obtaining the UAM–V model, EPA believes that the extensions of the comment period resulted in adequate time for comment. In any event, any commenter who was not able to gain access in the timeframe desired was able to use a comparable model, such as the Comprehensive Air Quality Model with Extensions (CAMx), which is not proprietary. For the purpose of responding to public comments, EPA is considering all information based on CAMx and similar models.

The Agency made available additional modeling runs used to determine emissions changes, costs and cost effectiveness for electricity generating units (EGUs). These runs were placed on the IPM Analyses web site at www.epa.gov/capi, with links to EPA's Office of Air and Radiation Policy and Guidance web site.

On August 10, the EPA placed in the docket and made available on the web site, modeling analyses and other information supporting today's action. As noted above, by notice dated August 24, 1998 (63 FR 45032), EPA published a notice of availability which stated that throughout the course of the rulemaking, EPA had placed information in the docket or made it available on various web sites. This information included inventory data and additional modeling runs. By placing those materials in the docket and informing the public of their availability, EPA provided 4–6 weeks for review and comment by the public. The EPA did receive comments concerning this information from the Utility Air Regulatory Group on September 9, and EPA is responding to those comments in the Response To Comments document. The EPA notes that the additional modeling analyses were performed in response to comments received on the NPR urging EPA to conduct State-by-State modeling. The Agency does not believe it is required to provide for additional comment on every action it takes in response to comment, particularly where, as here, the new information confirms the Agency's proposed conclusions. Therefore, the Agency did not further extend the comment period.

4. Public Hearings

The Agency conducted two hearings in Washington, DC, including a 2-day hearing on February 3–4, 1998 for the NPR, and a 1-day hearing on May 29, 1998 for the SNPR. Some commenters believe that additional public hearings should have been held in other locations in the OTAG region. The EPA believes these hearings provided reasonable opportunity for oral comment on the proposed rulemaking given the timeframes associated with this rulemaking. Therefore, the Agency did not schedule any additional hearings. The public also had an opportunity to submit written testimony within approximately 30 days after each hearing date.

G. Implementation of Revised Air Quality Standards

On July 18, 1997, EPA published its final rule for strengthening the NAAQS for ozone by establishing an 8-hour standard (62 FR 38856). Current monitoring data indicate that many areas in the East, Midwest and South violate the 8-hour NAAQS. Along with areas violating the 1-hour NAAQS, areas violating the 8-hour NAAQS are also affected by the transport of ozone across the East. The regional NO_X reduction strategy finalized in today's action will provide a mechanism to achieve reductions that will assist States in attaining and maintaining this revised standard. In fact, the regional reductions alone should be enough to enable the vast majority of the new counties violating the 8-hour NAAQS that are located in States throughout the East to attain the revised 8-hour standard.[9]

On July 16, 1997, President Clinton issued a directive on the implementation of the revised air quality standards. This implementation policy was described in the NPR (62 FR 60318, 60362–64). The EPA received numerous comments on this implementation policy and on EPA's plan to create a transitional classification[10] for 8-hour ozone nonattainment areas that meet certain

[8] Variable-Grid Urban Airshed Model.

[9] In the NPR (62 FR 60318, 60363), EPA provided estimates of the number of counties expected to attain as a result of the NO_X SIP call. The EPA will update this list in the coming months. The updated estimates of which counties will attain will be based on more current air quality data and on the State-by-State emissions budgets contained in today's final rule.

[10] The ''transitional classification'' EPA intends for 8-hour ozone nonattainment areas is further discussed in the NPR (62 FR 60318, 60363).

criteria. Since these comments concern implementation efforts for the revised 8-hour ozone standard and do not relate directly to the NO_X SIP call on which EPA is taking final action in this rulemaking, EPA is not responding in detail to the comments. The EPA will address implementation of the revised standard separately. In August 1998, EPA issued proposed guidance for public comment to explain the implementation policy in further detail and to provide details on SIP requirements for transitional areas (63 FR 45060, August 24, 1998). The EPA expects to finalize the August 1998 draft guidance, as well as guidance for areas other than transitional, by December 1998.[11]

H. Summary of Major Changes Between Proposals and Final Rule

This summary describes the major changes that have occurred since the NPR and SNPR in each of the following sections of today's final rule.

1. EPA's Analytical Approach (Section II.A)

- The NPR proposed two interpretations for the section 110(a)(2)(D)(i)(I) provisions concerning the ''significant contribution'' test. Under the first, EPA would examine certain factors relating to level of emissions and their ambient impact to determine whether to make a finding that all of the emissions from a particular State's sources contribute significantly to nonattainment or maintenance problems downwind. If EPA made such a finding, then EPA would examine certain cost factors to determine the extent to which the SIP for the State must mitigate (reduce) its emissions. Under the second interpretation, EPA would examine all of those factors together—level of emissions, ambient impact, and costs—to determine whether to make the finding with respect to a specified amount of emissions. If EPA made the finding, then it would require the SIP to eliminate that amount. In today's final rule, EPA is adopting the second interpretation. The EPA indicates, however, that it would adopt the same rule if it were instead implementing the first interpretation.

2. Cost Effectiveness of Emissions Reductions (Section II.D.)

- The methodology of determining cost effectiveness has not changed. For all sources, the inventory and as a result, the source-specific costs, in some cases, have changed. This results in a different overall budget level and a different overall cost-effectiveness value. For the non-EGUs, while the methodology has not changed, the analysis focuses on large non-EGU sources. The methodology in the NPR focused on all non-EGU sources.

3. Determination of Budgets (Section III.)

- For EGU, the EPA maintained the approach to use the higher, by State, of 1995 or 1996 heat input data to calculate baseline heat input rates for the NFR, and added 577 smaller units to the State budget inventories which had erroneously been omitted from the NPR. These units included electricity generating sources of 25 megawatts (MW) or less of electrical output and additional units not affected under the Acid Rain Program. Additional controls are not assumed for these sources, but they are added to the budget at baseline levels. The Agency has decided to use State-specific growth factors derived from application of the IPM using the 1998 Base Case and chose to retain the 0.15 lbs/mmBtu as the assumed uniform control level for EGU budget emissions determination.
- The EPA examined alternatives that focus on non-EGU point source reductions from the largest source categories, and within each of these categories assumed controls that would result in a regionwide average cost effectiveness less than $2000/ton. The resulting budget assumes the emissions reductions from large non-EGU sources that are among the most cost effective to control and does not include reductions from smaller sources and sources that, as a group, are not quite as cost effective or efficient to control, or are already covered by other Federal measures. As a result, this final rule assumes, for purposes of calculating the State NO_X budgets, the following emissions decreases from uncontrolled levels for the large (generally greater than 250 mmBtu or 1 ton/day non-EGU sources (no emission reductions are assumed for the smaller sources):

—Non-EGU boilers and turbines—60 percent decrease.
—Stationary internal combustion engines—90 percent decrease.
—Cement manufacturing plants—30 percent decrease.

It should be noted that point sources with capacities less than 250 mmBtu/hr but with emissions greater than 1 ton/day are not treated differently from sources with capacities greater than 250 mmBtu/hr for purposes of calculating the budget. This is a change from the NPR which included RACT controls on units with capacities less than 250 mmBtu/hr and emissions greater than 1 ton/day (see Section III.G.2.a). As under the proposal, the rule allows States to choose control measures other than the EPA-assumed controls to meet the numerical budgets.

- The EPA has implemented the following changes that the Agency proposed in the NPR for calculating baseline NO_X emissions from highway vehicles. A 1995 baseline is used for the final rule in place of the 1990 baseline used in the NPR. The Highway Performance and Monitoring System data were used to estimate States' 1995 vehicle miles traveled (VMT) by vehicle category, except in those cases where EPA accepted revisions offered in the comments. Today's action includes those mobile source reductions which EPA has determined are appropriate to implement on a national basis, and which have been promulgated in final form or are expected to be promulgated in final form before States are required to comply with their budgets. The highway vehicle budget components include the emission reductions resulting from implementation of the National Low Emitting Vehicle (NLEV) program, including the phase-in schedule agreed to by the States, automobile manufacturers, and EPA. The highway budget components do not include the effect of Tier 2 light-duty vehicle and truck standards and any associated fuel standards since these standards have not yet been proposed. The extent of the reformulated gasoline (RFG) and inspection and maintenance (I/M) programs was not assumed to change beyond that assumed for the NPR, except for those States that were able to demonstrate that the NPR's modeling assumptions did not conform to the State's SIP and did not reflect CAA requirements.
- The EPA has chosen to retain the 1990 baseline inventories for nonroad mobile sources presented in the NPR for today's action, with additional changes made in response to public comments. The control strategies assumed for calculating the nonroad and stationary area source budget components have not changed from the SNPR.

4. NO_X Control Implementation and Budget Achievement Dates (Section V)

- The EPA proposed that the SIP revisions require full implementation of the necessary State measures by September 2002 and took comment on a range of dates from September 2002 through September 2004. Based on

[11] For a complete listing of the guidance and other actions EPA plans to issue to implement the revised ozone and PM NAAQS, see a table on EPA's implementation website: http://ttnwww.rtpnc.epa.gov/implement/actions.htm.

public comments and feasibility analyses conducted by EPA, the Agency is requiring an implementation date of May 1, 2003. The Agency is also providing some compliance flexibility to States for the 2003 and 2004 ozone seasons by establishing State compliance supplement pools. This is described in Section III.F.6.

5. SIP Criteria (Section VI.A)

• The Agency has determined that the additional SIP approvability criteria, as proposed in the SNPR, should apply not only when States choose to regulate EGUs (63 FR 25912), but also when States choose to regulate large steam-producing units (i.e., combustion turbines and combined cycle systems with a capacity greater than 250 mmBtu/hr).

• The Agency proposed revisions to part 51 requiring continuous emissions monitoring systems (CEMS) on all large electrical generating and steam-producing sources which States elect to subject to emissions reduction requirements in response to this rulemaking. The EPA took comment on requiring that, if a State chooses to regulate these sources to meet the SIP call, the SIP must require these sources to use the NO_X mass monitoring provisions of part 75, subpart H, to demonstrate compliance with applicable emissions control requirements. After considering comments, the Agency is requiring that, in these circumstances, the SIP specify that large sources comply with the monitoring provisions of part 75, subpart H, which includes non-CEMS monitoring options for units that are infrequently operated or units that have low mass emissions.

6. Emissions Reporting Requirements for States (Section VI.B)

• The proposed rule required that States report full-year, as well as ozone-season, emissions from all sources for the triennial inventories commencing with year 2002 emissions and the 2007 inventory, and for those sources for which reports had to be submitted annually starting with year 2003 emissions. The final rule requires only ozone-season emissions reporting for all sources.

• In the SNPR, the EPA proposed, for purposes of reporting requirements, to define a point source as a non-mobile source which has NO_X emissions of 100 tons/year or greater. Under today's action, States have the option of establishing a smaller emission threshold than 100 tons/year of NO_X emissions in defining point source. This will allow the definition of point source to remain consistent with current definitions in local areas.

7. NO_X Budget Trading Program (Section VII.)

• For States that choose to participate in the NO_X Budget Trading Program, the preamble clarifies the intent of the model rule and identifies areas of the rule where States have flexibility to include variations in their State rules.

• In the SNPR, the Agency solicited comment on a range of options for incorporating banking into the trading program. After considering these comments, the Agency is including banking provisions in the final rule. The provisions allow for unlimited banking starting in 2003 and includes a flow control mechanism to limit the emissions variability associated with banking.

• One of the banking approaches presented in the SNPR included the option for sources to generate and use early reduction credits. Consistent with the provisions of the NO_X SIP call which provide for State compliance supplement pools, the final rule allows States to issue early reduction credits for certain NO_X emissions reductions achieved between September 30, 1999 and May 1, 2003.

• The final rule clarifies the timing requirements for State submission of allowance allocations to EPA and, as proposed, lays out an allocation approach. Each State remains free to adopt the final rule's allocation approach or adopt an allocation scheme of its own, provided it meets the specified timing requirements, requires new sources to hold allowances, and does not allocate more allowances than are available in the State trading budget.

8. Interaction with Title IV NO_X Rule (Section VIII.)

• In the SNPR, EPA proposed revisions to part 76 addressing the interaction between title IV and the NO_X SIP call. In this final rule, EPA explains that the Agency is not adopting any of the proposed revisions to part 76.

9. Administrative Requirements (Section X.)

• NPR Section VIII, Regulatory Analyses, has been replaced in the final rule by Section X.A, Executive Order 12866: Regulatory Impacts Analysis. The new final rule Section X.A indicates that EPA has prepared a RIA for the final rule and cites the cost and benefit estimates from that analysis.

• The final rule adds several Sections under X, Administrative Requirements, that were absent from the NPR. These include: Paperwork Reduction Act; Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks; Executive Order 12898: Environmental Justice; Executive Order 12875: Enhancing the Intergovernmental Partnerships; Executive Order 13084: Consultation and Coordination with Indian Tribal Governments; Judicial Review; and Congressional Review Act. These new Sections provide a more comprehensive summary of the Acts and Executive Orders that could apply to the final rule. Each Section identifies the requirements of the relevant Act or Executive Order, indicates EPA's interpretation of whether the Act or Executive Order actually applies to this rulemaking, and, if so, indicates how the Agency has addressed the Act or Executive Order.

II. EPA's Analytical Approach

A. Interpretation of the CAA's Transport Provisions

As indicated in the NPR, 62 FR 60323, the primary statutory basis for today's action is the ''good neighbor'' provision of section 110(a)(2)(D)(i)(I), under which, in general, each SIP is required to include provisions assuring that sources within the State do not emit pollutants in amounts that significantly contribute to nonattainment or maintenance problems downwind. This statutory requirement applies to SIPs under both the 1-hour ozone NAAQS and the 8-hour ozone NAAQS.

1. Authority and Process for Requiring SIP Submissions Under the 1-Hour Ozone NAAQS

a. Authority for Requiring SIP Submissions under the 1-Hour NAAQS. Each State is currently required to have in place a SIP that implements the 1-hour ozone NAAQS for areas to which that standard still applies. In the NAAQS rulemaking, EPA determined that the 1-hour NAAQS would cease to apply to areas that EPA determines have air quality in attainment of that NAAQS (40 CFR 50.9(b)). In two recent rulemakings, EPA identified numerous areas of the country to which the 1-hour NAAQS no longer applies. ''Final Rule: Identification of Ozone Areas Attaining the 1-Hour Standard and to Which the 1-Hour Standard is No Longer Applicable,'' (63 FR 31014, June 5, 1998); ''Final Rule: Identification of Additional Ozone Areas Attaining the 1-Hour Standard and to Which the 1-Hour Standard is No Longer Applicable,'' (63 FR 27247, July 22, 1998).

The 1-hour NAAQS remains applicable to areas whose air quality continues to monitor nonattainment. As noted above in Section I.B, General

Factual Background, these include many major urban areas in the eastern half of the United States. States that contain these areas remain responsible for meeting CAA requirements applicable to those areas for the purpose of attaining the 1-hour NAAQS. For example, States are responsible for attainment demonstrations for areas designated nonattainment and classified as moderate or higher.

By the same token, States that are upwind of these areas are responsible to meet the ''good neighbor'' requirements of section 110(a)(2)(D). This responsibility is not alleviated simply because, for areas other than the current nonattainment areas, the 8-hour NAAQS has replaced the 1-hour NAAQS.

b. Process for Requiring SIP Submissions under the 1-Hour NAAQS. As explained in the NPR, the appropriate route for EPA to require SIP submissions under section 110(a)(2)(D)(i)(I) with respect to the 1-hour standard is issuance of a ''SIP call'' under section 110(k)(5).[12] Section 110(k)(5) authorizes EPA to find that a SIP is substantially inadequate to meet a CAA requirement and to require (''call for'') the State to submit, within a specified period, a SIP revision to correct the inadequacy. Specifically, section 110(k)(5) provides, in relevant part:

> Whenever the Administrator finds that the applicable implementation plan for any area is substantially inadequate to attain or maintain the relevant [NAAQS], to mitigate adequately the interstate pollutant transport described in section 176A or section 184, or to otherwise comply with any requirement of this Act, the Administrator shall require the State to revise the plan as necessary to correct such inadequacies. The Administrator shall notify the State of the inadequacies, and may establish reasonable deadlines (not to exceed 18 months after the date of such notice) for the submission of such plan revisions.

By today's action, EPA is determining that the SIPs for the specified jurisdictions are substantially inadequate to comply with the requirements of section 110(a)(2)(D)(i)(I) because the relevant SIPs do not contain adequate provisions prohibiting their sources from emitting amounts of NO_X emissions that contribute significantly to nonattainment in downwind areas that remain subject to the 1-hour NAAQS. Based on these determinations, EPA is requiring the identified States to submit SIP revisions containing adequate provisions to limit emissions to the appropriate amount.

If a State does not submit the required SIP provisions in response to this SIP call, EPA will issue a finding that the State failed to make a required SIP submittal under section 179(a). This finding has implications for sanctions as well as for EPA's promulgation of Federal implementation plans (FIPs). Sanctions and FIPs are discussed in Section VI, SIP Criteria and Emissions Reporting Requirements.

(1) Commenters' Arguments Concerning the Transport Provisions. Commenters argued that EPA does not have unilateral authority to issue a SIP call under section 110(k)(5) to require States to remedy SIPs that do not meet the requirements of section 110(a)(2)(D). The commenters noted that when Congress amended the CAA in 1990, Congress provided that the sole authority for EPA and States to address interstate transport of pollution is through transport commissions. In support, the commenters state that Congress: (i) Added sections 176A and 184, which authorize the establishment of transport regions and the formation of transport commissions; (ii) revised section 110(k)(5) to refer to those transport provisions; and (iii) revised section 110(a)(2)(D)(i) to require that SIP provisions designed to eliminate interstate pollutant transport be consistent with other CAA requirements. According to the commenters, these provisions, read as a whole, mandate that if EPA believes that a transport problem exists, EPA's sole recourse is to form a transport region under sections 176A and/or 184; EPA may issue a SIP call to mandate compliance with section 110(a)(2)(D)(i) only in response to a recommendation of the transport region. The commenters also claim that this scheme is sensible because it provides a consensual forum for States to address interstate pollution rather than allowing unilateral action on the part of EPA or a State.

The EPA disagrees with the commenters' conclusion that these statutory provisions make clear that EPA cannot require a State to address interstate transport without first establishing a transport commission and in the absence of a recommendation from the transport commission. There is no language of limitation in sections 110(a)(2)(D) or (k)(5), or 176A, or 184. Nor is there any support in the legislative history for such a narrow reading of the statute. Moreover, under the commenters' interpretation, the CAA Amendments of 1990 have placed greater constraints on States' and EPA's ability to address the interstate transport of pollution. Such an interpretation would be inconsistent with the overall purpose of the CAA to ensure healthful air. Thus, EPA believes that the transport provisions were added as an additional tool to address interstate transport but were not intended to preclude other methods of addressing interstate pollution than prior to passage of the amendments.

Under the 1990 Amendments, Congress recognized the growing evidence that ozone and its precursors can be transported over long distances and that the control of transported ozone was a key to achieving attainment of the ozone standard across the nation (Cong. Rec. S16903 (daily ed. Oct. 27, 1990) (statement of Sen. Mitchell); S16970 (conference report) S16986–87 (statement of Sen. Lieberman)). Thus, in 1990, Congress added a new mechanism to address interstate transport. Specifically, Congress enacted sections 176A and 184, which provide a mechanism for States to work together to address the interstate transport problem. However, by their terms, these sections simply provide authority for EPA to designate transport regions and establish transport commissions. There is nothing in the language of these provisions that indicates that they supersede the other statutory mechanisms for addressing interstate transport, or that they now provide the sole mechanism for resolving interstate pollution transport.

Moreover, although Congress expressly added these two provisions through the 1990 Amendments, Congress did not in any way limit section 110(a)(2)(D), which requires States to address interstate transport in their SIPs. The addition of the language providing that States' actions under section 110(a)(2)(D) be ''consistent with [title I] of the Act'' cannot be read to limit the controls States may adopt to meet section 110(a)(2)(D) to those recommended by a transport commission.[13] After all, the transport region provisions are only two of many provisions in title I. Rather, this

[12] As discussed in the NPR and in greater detail further below, the basis for requiring a transport-related SIP revision for the 8-hour standard is the requirement in section 110(a)(1) that States submit SIPs meeting the requirements of section 110(a)(2) within 3 years (or an earlier date established by EPA) of promulgation of a new or revised NAAQS. This is discussed in further detail below.

[13] Taken to its logical conclusion, the commenters' argument would mean that States are precluded from submitting a section 110(a)(2)(D) SIP unless it reflects measures recommended through the transport commission process. The EPA does not believe that Congress would first establish a specific mandate (to submit a SIP to address interstate transport) and then limit it in such a cryptic fashion. If Congress intended section 110(a)(2)(D) SIPs to only reflect transport commission recommendations, Congress could have specifically referenced sections 176A and 184 in section 110(a)(2)(D), rather than generally providing that SIPs be ''consistent'' with title I of the CAA.

language concerning consistency should be read as clarifying that any section 110(a)(2)(D) requirement must be consistent with other provisions of title I. Similarly, this language makes explicit that SIP revisions required in accordance with the procedures of the transport provisions would meet the requirements of section 110(a)(2)(D)(i).

Furthermore, it is significant that Congress did not in any sense bind EPA's ultimate discretion to determine whether State plans appropriately address interstate transport. Under sections 176A and 184, the States may only make recommendations to EPA. Thus, under the transport provisions, as well as the general SIP requirements of section 110(a)(2), EPA must ultimately decide whether the SIP meets the applicable requirements of the CAA. If, as the commenters contend, EPA is limited to calling on States to address interstate transport only by strategies recommended by the State, then EPA would be precluded from ensuring that States address interstate transport. For example, EPA could establish a transport commission but the commission could fail to make recommendations or make insufficient recommendations. (Section 176A provides that transport commissions may make recommendations to EPA only by ''majority vote of all members'' other than those representing EPA.) Such a reading of the statute would be absurd in light of the growing recognition at the time of the 1990 Amendments that transport is a real threat to the primary purpose of title I of the CAA—attainment of the NAAQS.

By the same token, in amending section 110(k)(5) in the 1990 Amendments, Congress did not add anything that explicitly provides that, in the case of interstate transport, section 110(k)(5) would apply only when EPA approved (or substituted measures for) a transport commission's recommendations. The reference in section 110(k)(5) to the transport provisions of sections 176A and 184 does not preclude EPA's use of the SIP call provision to call on States to ensure their SIPs meet the requirements of section 110(a)(2)(D)(i). Section 110(k)(5) also provides for EPA to call on States ''to otherwise comply with requirements of this Act;'' among the requirements in chapter I of the CAA is the requirement in section 110(a)(2)(D). The reference in section 110(k)(5) to the transport provisions simply makes explicit that EPA may employ section 110(k)(5) for the additional purpose of requiring SIPs to include the control measures as recommended by transport commissions and approved by EPA under the transport provisions.

Moreover, there is no indication in the legislative history of the 1990 Amendments that Congress intended the sections 176A and 184 transport provisions to supersede the section 110(k)(5) SIP call mechanism for ensuring compliance with section 110(a)(2)(D)(i). Reading the transport provisions to supersede the SIP call mechanism would constitute a significant change from the CAA as it read prior to the 1990 Amendments. Even if the statute is ambiguous as to whether the transport provisions supersede the SIP call mechanism—and EPA believes the statute is clear that the transport provisions do not supersede—congressional silence would suggest that Congress did not intend such a significant change (See generally *Harrison* v. *PPG Industries, Inc.*, 446 U.S. 578, 602, 100 S.Ct. 1889, 1902, 64 L.Ed.2d 525 (1980) (Rehnquist, J., dissenting), *cited with approval in Chisom* v. *Roemer*, 501 U.S. 380, 396 n. 23, 111 S.Ct. 2354, 2364 n. 23, 115 L.Ed.2d 348 (1991)).

Finally, the commenter asserts that EPA's interpretation of the CAA to allow a SIP call in the absence of a transport commission recommendation reads out of the CAA the consensual transport commission procedures under sections 176A and 184. This is simply not true. The EPA interprets the transport commission process to be one tool to assess and address interstate transport. In fact, the Northeast Ozone Transport Commission, under section 184, has been active since enactment of the 1990 Amendments. In 1995, EPA approved a recommendation of that commission (60 FR 4712[14]). Transport commissions remain a viable means for dealing with interstate transport. Furthermore, contrary to the general implication of the commenter's remark, the OTAG process, though not a formal transport commission, provided an opportunity not only for Federal and State governments to assess jointly the transport issue, but also involved industry, environmental groups and others. The EPA based its SIP call on information developed through OTAG, as well as additional analyses performed by the Agency and information submitted by a variety of groups during the comment period on the proposed rule. Thus, the OTAG process contained consensual elements.

(2) Commenters' Arguments Concerning the Virginia case. Under one of the approaches described in the proposed rule, EPA proposed to determine, for each of various upwind States, the aggregate ''amounts'' of air pollutants (NO_X) that contribute significantly to nonattainment, and that, therefore must be prohibited by the various SIPs. The NO_X emissions budget for each State is an expression of the amount of NO_X emissions that would remain after the State prohibits the amount that contributes significantly to downwind nonattainment. In the final rule issued today, EPA has continued this approach, establishing emissions budgets for each of the 23 jurisdictions based on required reductions. This determination is an important step toward assuring that overall air quality standards are met downwind.

Commenters argue that even if EPA has authority to call on States to address interstate transport, EPA does not have the authority under section 110(a)(2)(D) to mandate that upwind States limit NO_X emissions to specified amounts. Rather, according to this view, EPA's authority is limited to determining that the upwind States' SIPs are inadequate, and generally requiring the upwind States to submit SIP revisions to correct the inadequacies. The upwind States would then, according to this view, submit a SIP revision that implements what the upwind States determine to be the appropriate amount of NO_X reductions. If EPA believes that those amounts are too small to correct the inadequacy, EPA could disapprove the SIP revisions.

Proponents of this view rely on the recent decision in *Virginia* v. *EPA*, 108 F.3d 1397, 1406–10 (D.C. Cir. 1997) (*Virginia*) (citing *Train* v. *NRDC*), in which the court vacated EPA's SIP call on the basis that through it, EPA gave States no choice but to adopt the California low emission vehicle (LEV) program. The court found that the language in section 110(k)(5) that provides EPA with the authority to call on a State to revise its SIP ''as necessary'' to correct a substantial inadequacy did not change the longstanding precept that States have the primary authority for determining the mix of control measures needed to attain the NAAQS.

The EPA disagrees that the CAA prohibits EPA from establishing an emissions budget through a SIP call requiring upwind States to prohibit emissions that contribute significantly to downwind nonattainment. Section

[14] In *Commonwealth of Virginia* v. *EPA*, 108 F.3d 1397 (D.C. Cir. 1997), the court vacated EPA's SIP call in response to the Northeast Ozone Transport Commission's recommendation on the basis that the EPA could not require States to adopt a specific control measure under its section 110(k)(5) authority and that, in any event, EPA could not require States to adopt stricter motor vehicle emission standards under either section 110(k)(5) or section 184.

110(a)(2)(D) is silent regarding whether States or EPA are to determine the level of emission reductions necessary to mitigate significant contribution. The caselaw cited by the commenters only provides that States are primarily responsible for determining the mix of control measures—not the aggregate emission reduction levels that are necessary. Moreover, *Train* v. *NRDC*, which underlies the *Virginia* court's decision, relied on section 107(a) of the CAA, which specifies only that each State is primarily responsible for determining a control strategy to attain the NAAQS ''within such State.''

Section 110(a)(2)(D) does not provide who—EPA or the States—is to determine the level of emission reductions necessary to address interstate transport. As quoted above, section 110(a)(2)(D)(i)(I) requires that SIPs contain ''adequate provisions prohibiting * * * [sources] from emitting any air pollutant in amounts which will contribute significantly to nonattainment'' downwind. Nor does this provision indicate the criteria for determining the ''amounts'' of pollutants that contribute significantly to nonattainment downwind. Nor does this provision indicate the process for determining those ''amounts,'' including whether EPA or the States should carry out this responsibility.[15] Under *Chevron U.S.A., Inc.* v. *Natural Resources Defense Council*, 468 U.S. 1227, 105 S.Ct. 28, 82 L.Ed.2d 921 (1984) (*Chevron*), because the statute does not answer these specific issues, EPA has discretion to provide a reasonable interpretation.

Neither the decision in *Virginia*, nor the body of caselaw upon which it relies, addresses this issue. Rather, these cases address solely the division between the States and EPA regarding the initial identification of control measures necessary to attain the ambient air quality standards. The issue before the court in Virginia was whether EPA had offered States a choice in selecting control measures or instead had mandated the adoption of a specific control measure. Relying on *Train* v. *NRDC*, 421 U.S. 60, 95 S.Ct. 1470, 43 L.Ed.2d 731 1975), the *Virginia* court found that under title I of the CAA, EPA is required to establish the overall air quality standards, but the States are primarily responsible for determining the mix of control measures needed to meet those standards and the sources that must implement controls, as well as the applicable level of control for those sources. The EPA must then review the State's determination only to the extent of assuring that the overall air quality standards are met. If EPA determines that the SIP's mix of control measures does not result in achieving the overall air quality standards, EPA is required to disapprove the SIP and promulgate a FIP, under which EPA selects the sources for emissions reductions (*Virginia*, 108 F.3d at 1407–08, *citing Train* v. *NRDC*, 421 U.S. 60, 95 S.Ct. 1470, 43 L.Ed.2d 731 (1975); *Union Electric Co.* v. *EPA*, 427 U.S. 246, 96 S.Ct. 2518, 49 L.Ed.2d 474 (1976)). This line of cases, which focuses on the selection of controls, does not address whether EPA or the States—in the first instance—should determine the aggregate amount of reductions necessary to address interstate transport.

Moreover, *NRDC* v. *Train* addresses State plans for purposes of intrastate emissions planning. In determining that States have the primary authority for determining the control measures needed to attain the standard, the court relied on section 107(a) of the CAA, which provided (and still provides) that:

> Each State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State by submitting an implementation plan which will specify the manner in which national primary and secondary ambient air quality standards will be achieved and maintained within each air quality region in such State.''

(421 U.S. at 64, 95 S.Ct at 1474–75 (emphasis added)).

Thus, the underlying support for the court's determination in *Train* v. *NRDC* applies only where a State is determining the mix of controls within its boundaries, not to the broader task of determining the aggregate emissions reductions needed in conjunction with emissions reductions from a number of other States in order to address the impact of transported pollution on downwind States.[16]

Although the cases to date have not addressed directly whether it is the province of EPA or the States to determine the aggregate amounts of emissions to be prohibited (and hence, the amounts that may remain—i.e., the emissions budgets), EPA believes it reasonable to interpret the ambiguity in section 110(a)(2)(D)(i)(I) to include this determination among EPA's responsibilities, particularly in the current circumstances. Determining the overall level of air pollutants allowed to be emitted in a State is comparable to determining overall standards of air quality, which the courts have recognized as EPA's responsibility, and is distinguishable from determining the particular mix of controls among individual sources to attain those standards, which the caselaw identifies as a State responsibility. In *Train*, a State was required to assure that its own air quality attained overall air quality standards and to implement emissions controls to do so. Under these circumstances, the court clarified that while the responsibility for determining the overall air quality standards was EPA's, the responsibility for determining the specific mix of controls designed to achieve that air quality was the State's. By comparison, as stated earlier, a transport case, under section 110(a)(2)(D)(i), does not concern any requirement of the upwind State to assure that its own air quality attains overall air quality standards. Rather, a transport case concerns the upwind State's requirement to assure that its emissions are reduced to a level that will not contribute significantly to nonattainment downwind. Determining this overall level of reductions for the upwind State is analogous to determining overall air quality standards, and, thus, should be the responsibility of EPA.

Once EPA determines the overall level of reductions (by assigning the aggregate amounts of emissions that must be eliminated to meet the requirements of section 110(a)(2)(D)), it falls to the State to determine the appropriate mix of controls to achieve those reductions. Unlike the regulation at issue in *Virginia*, today's regulation establishing emission budgets for the States does not limit the States to one set of emission controls. Rather, the States will have significant discretion to choose the appropriate mix of controls to meet the emissions budget. The EPA has based the aggregate amounts to be prohibited on the availability of a subset of cost-effective controls that are among the most cost effective available. As explained elsewhere in this final rule and the NPR, the State may choose from a broader menu of cost-effective, reasonable alternatives, including some (e.g., vehicle inspection and maintenance programs and reformulated

[15] The EPA is not contending that the ''as necessary'' language in section 110(k)(5) provides the basis for EPA's authority to identify the emissions budget for upwind States.

[16] The court's decision in *Train* v. *NRDC* appears to rely on the plain language of the statute in holding that a State is primarily responsible for determining the mix of control measures necessary to demonstrate attainment within that State's borders. The court in *Virginia* appears to adopt this ''plain meaning'' interpretation without addressing that the language in section 107(a) applies only to intrastate issues. This issue is not relevant in the present case, however, since States are free to decide the mix of control measures under today's final action.

gasoline) that may even be more advantageous in light of local concerns.

The task of determining the reductions necessary to meet section 110(a)(2)(D) involves allocating the use of the downwind States' air basin. This area is a commons in the sense that the contributing State or States have a greater interest in protecting their local interests than in protecting an area in a downwind State over which they do not have jurisdiction and for which they are not politically accountable. Thus, in general, it is reasonable to assume that EPA may be in a better position to determine the appropriate goal, or budget, for the contributing States, while leaving to the contributing States' discretion to determine the mix of controls to make the necessary reductions.

The EPA's decision to assign the budgets in the final rule is particularly reasonable. Today's rulemaking involves almost half the States in the Nation, and although these States participated in OTAG beginning more than 3 years ago, they still have not agreed on whether particular upwind States should be treated as having sources whose emissions contribute significantly to downwind nonattainment, what the aggregate level of emissions reductions should be, or what the State-by-State reductions should be. The sharply divergent positions taken by the States in their comments on the NPR and SNPR raise doubts that those disagreements could ever be resolved by consensus. It is most efficient—indeed necessary—for the Federal government to establish the overall emissions levels for the various States. This is particularly true for an interstate pollution problem such as the one being dealt with in this action where the downwind areas at issue are affected by pollution coming from several States and the actions taken by each of the concerned States could have an effect on the appropriate action to be taken by another State. For example, if EPA did not specify the emissions to be prohibited from each of the various States affecting New York City, each of those States might claim it could reduce its emissions less provided other States did more. Or, a State close to New York might assert that it could just as effectively deal with its contribution to New York through additional VOC, rather than NO_X, reductions and submit a section 110(a)(2)(D) SIP based on a VOC-control rather than NO_X-control strategy. These choices, however, even assuming they were valid, necessarily relate to the choices that would need to be made by the other upwind States (e.g., Pennsylvania's choice of a VOC-dominated 110(a)(2)(D) control strategy to deal with its contribution to New York could affect what Ohio or New Jersey would need to do to deal with their own contributions by lowering the overall level of NO_X reductions being obtained throughout the pertinent region). Where many States are involved and the choices of each individual State could affect the choices and decisions of the other States the need for initial federal action is manifest. The EPA's action to determine the amount of NO_X emissions that each of the States must prohibit in this widespread geographic area is needed to enable the States to decide expeditiously how to achieve those reductions in an efficient manner that will not undermine the actions of another State. By notifying each State in advance of its reduction requirements, EPA enables each State to develop its plan with full knowledge of the amount and kind of reductions that must be achieved both by itself and other affected States. The EPA's action provides the minimum framework necessary for a multi-state solution to a multi-state problem while preserving the maximum amount of state flexibility in terms of the specific control measures to be adopted to achieve the needed emission reductions. The reasonableness of EPA's approach to the interstate ozone transport problem was recently recognized by a US Court of Appeals in the context of upholding EPA's redesignation of the Cleveland ozone nonattainment area to attainment in light of EPA's approach to the regional transport problem. In the course of doing so the court rejected the contention that a separate analysis of the current adequacy of the Cleveland SIP under section 110(a)(2)(D) was required as a prerequisite to redesignation. The court, after describing the November 7, 1997 proposed SIP call and the path EPA was on to deal with this multi-state regional problem, upheld EPA's redesignation and stated that ''[w]e find that the EPA's approach to the regional transport problem is reasonable and not arbitrary or capricious.'' *Southwestern Pennsylvania Growth Alliance* v. *Browner,* 144 F.3d 984, 990 (6th Cir. 1998).

As noted above, commenters have argued that if EPA determines to issue any SIP call, the SIP call must be more general (i.e., one that simply requires revised SIPs from upwind areas) and not specify the amounts of NO_X emissions that those areas must prohibit. However, if EPA issued a general SIP call and an upwind State responded by submitting an inadequate SIP revision, EPA would disapprove that SIP, and in the disapproval rulemaking, EPA would be obliged to justify why the submitted SIP was unacceptable. Without determining an acceptable level of NO_X reductions, the upwind State would not have guidance as to what is an acceptable submission. The EPA's determination, as part of the issuance of the SIP call, of the amounts of NO_X emissions the SIPs must prohibit obviously provides for more efficient and smooth-running administrative processes at both the State and Federal levels. For the same reasons that EPA believes it is appropriate for the Agency to establish the emissions budgets under the authority of section 110(a)(2)(D) and (k)(5), EPA believes that it is necessary to do so through a rule under the general rulemaking authority of section 301(a). Setting such a rule is necessary, as a practical matter, for the Administrator's effective implementation of section 110(a)(2)(D). *See NRDC* v. *EPA,* 22 F.3d 1125, 1146–48. Without such a rule the States could be expected to submit SIPs reflecting their conflicting interests, which could result in up to 23 separate SIP disapproval rulemakings in which EPA would need to define the requirements that each of those States would need to meet in their later, corrective SIPs. That in turn would trigger a new round of SIP rulemakings to judge those corrective SIPs. The delay attendant to that process would thwart timely attainment of the ozone standards.

2. Authority and Process for Requiring SIP Submissions under the 8-Hour Ozone NAAQS

a. Authority for Requiring SIP Submissions under the 8-Hour NAAQS. (1) SIP Submissions Under CAA Section 110(a)(1). In the NPR and SNPR, EPA proposed to require the 23 upwind jurisdictions to submit SIP revisions to reduce emissions that exacerbate ozone problems in downwind States under the 8-hour ozone NAAQS, as well as the 1-hour NAAQS. The EPA recognized that under the 8-hour NAAQS, areas have not yet been designated as attainment, nonattainment, or unclassifiable, and are not yet required to have SIPs in place. Even so, EPA proposed that upwind areas be required to submit SIPs meeting the requirements of section 110(a)(2)(D)(i)(I) with respect to the 8-hour NAAQS.

In today's action, EPA is confirming its view that it has authority under the 8-hour NAAQS to require SIP submittals under section 110(a)(2)(D)(i)(I) to reduce NO_X emissions by the prescribed amounts. Section 110(a)(1) provides, in relevant part—

Each State shall * * * adopt and submit to the Administrator, within 3 years (or such shorter period as the Administrator may prescribe) after the promulgation of a national primary ambient air quality standard (or any revision thereof) * * * a plan which provides for implementation, maintenance, and enforcement of such primary standard in each (area) within such State.

Section 110(a)(2) provides, in relevant part—

Each implementation plan submitted by a State under this Act shall be adopted by the State after reasonable notice and public hearing. Each such plan shall [meet certain requirements, including those found in section 110(a)(2)(D)].

The provisions of section 110(a)(1) and (a)(2) apply by their terms to all areas, regardless of whether they have been designated as attainment, nonattainment, or unclassifiable under section 107. The plain meaning of these provisions, read together, is that SIP revisions are required under the revised NAAQS within 3 years of the date of revision, or earlier if EPA so requires, and that those SIP revisions must meet the requirements of section 110(a)(2), including subparagraph (D).

That the SIP submission requirements of section 110(a)(1) are triggered by the promulgation of a new or revised NAAQS is made even clearer by comparing section 172(b), which applies by its terms only to areas that have been designated nonattainment under section 107. Section 172(b) provides, in relevant part—

At the time the Administrator promulgates the designation of any area as nonattainment with respect to a [NAAQS] under section 107(d) * * *, the Administrator shall establish a schedule according to which the State containing such area shall submit a plan or plan revision * * * meeting the applicable requirements of subsection (c) of this section and section 110(a)(2) * * * Such schedule shall at a minimum, include a date or dates, extending no later than 3 years from the date of the nonattainment designation, for the submission of a plan or plan revision * * * meeting the applicable requirements of subsection (c) of this section and section 110(a)(2) * * *

Section 172(b) establishes the schedule for submissions due with respect to nonattainment areas under sections 172(c) and 110(a)(2). The section 172(c) requirements apply only with respect to areas designated nonattainment.[17]

[17] As quoted above, section 172(b) refers to ''applicable requirements of * * * section 110(a)(2).'' This reference appears to mean those requirements of section 110(a)(2) that either (i) relate to all SIP submissions, such as the requirement for reasonable notice and public hearing in the language at the beginning of section 110(a)(2); or (ii) relate particularly to SIP submissions required for nonattainment areas, but that have not yet been submitted by the State.

In the NPR, EPA proposed that section 110(a)(1) mandates SIP submissions meeting the requirements of section 110(a)(2)(D) and provides full authority for EPA to establish a submission date within 3 years of the July 18, 1997 8-hour ozone NAAQS promulgation date (62 FR 38856 (NAAQS rulemaking): 62 FR 60325 (NOx SIP call NPR)). The EPA further asserted in the NPR that EPA has the authority to establish different submittal schedules for different parts of the section 110(a)(1) SIP revision, and that EPA may require the section 110(a)(2)(D) submittal first so that upwind reductions may be secured at an earlier stage in the regional SIP planning process (62 FR 60325). Subsections (ii) and (iii) of this section further elaborates on the reasoning underlying EPA's decision to retain its proposal to require SIP submissions under section 110(a)(2)(D) for the 8-hour standard.

(2) Commenters and the Definition of ''Nonattainment.'' Commenters challenged several aspects of EPA's proposal to evaluate the contribution of upwind areas under the 8-hour NAAQS. Commenters asserted that section 110(a)(2)(D)(i) applies to constrain emissions from upwind sources only with respect to downwind areas that are designated nonattainment. According to these commenters, until EPA designates areas nonattainment under the 8-hour NAAQS, EPA has no authority to require SIP submissions, under section 110(a)(1), from upwind areas with respect to the 8-hour NAAQS. One commenter pointed out that the new source review requirements and ozone nonattainment requirements enacted in the 1990 Amendments apply only to areas designated nonattainment.

The EPA disagrees with this comment. Section 110(a)(2)(D)(i)(I) provides that a SIP must prohibit emissions that ''contribute significantly to nonattainment in * * * any other State.''[18] The provision does not, by its terms, indicate that this downwind ''nonattainment'' must already have been designated under section 107 as a nonattainment ''area.'' If the provision were to employ the term ''area'' in conjunction with the term ''nonattainment,'' then it would have to be interpreted to apply only to areas designated nonattainment. Other provisions of the CAA do employ the term ''area'' in conjunction with ''nonattainment,'' and these provisions clearly refer to areas designated nonattainment (e.g., sections 107(d)(1)(A)(i), 181(b)(2)(A), 211(k)(10)(D)). Similarly, the provisions to which the commenter appeared to refer—section 172(b)/172(c)(5) (new source review) and section 181(a)(1)/182 (classified ozone nonattainment area requirements)—by their terms apply to a nonattainment ''area.'' In contrast, section 110(a)(2)(D) refers to only ''nonattainment,'' not to a nonattainment ''area.''

[18] Section 110(a)(2)(D)(i)(I) further provides that a SIP must prohibit emissions that ''interfere with maintenance by * * * any other State.''

By the same token, section 176A(a) authorizes EPA to establish a transport region whenever ''the Administrator has reason to believe that the interstate transport of air pollutants from one or more States contributes significantly to a violation of a [NAAQS] in one or more other States.'' This reference to ''a violation of a [NAAQS]'' makes clear that EPA is authorized to form a transport region when an upwind State contributes significantly to a downwind area with nonattainment air quality, regardless of whether the downwind area is designated nonattainment. The EPA believes that section 110(a)(2)(D) should be read the same way in light of the parallels between section 110(a)(2)(D) and section 176A(a). Both provisions address transport and both are triggered when emissions from an upwind area ''contribute significantly'' downwind. It seems reasonable to apply a consistent approach to the type of affected downwind area, which would mean interpreting the term ''nonattainment'' in section 110(a)(2)(D) as synonymous with the phrase ''a violation of a [NAAQS]'' in section 176A(a). The CAA contains other provisions, as well, that refer to the factual, air quality status of a particular area as opposed to its designation status. These provisions include, among others, (i) sections 172(c)(2) and 171(1), the reasonable further progress requirement, which requires nonattainment SIPs to provide for ''such annual incremental reductions in emissions * * * as * * * may * * * be required * * * for the purpose of ensuring attainment of the [NAAQS]'' (emphasis added); and (ii) section 182(c)(2), the attainment demonstration requirement, which mandates a ''demonstration that the [SIP] * * * will provide for attainment of the [NAAQS]'' (emphasis added). The emphasized terms clearly refer to air quality status. In a series of notices in the **Federal Register**, EPA relied on these references to air quality status in determining that areas seeking to redesignate from nonattainment to attainment did not need to complete ROP SIPs or attainment demonstrations—even though those requirements generally applied to areas designated nonattainment—as long as the air quality for those redesignating areas was, in fact, in attainment. See ''State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990; Proposed Rule,'' 57 FR 13498, 13564 (April 16, 1992); ''Determination of Attainment of Ozone Standard for Salt Lake and Davis Counties, Utah, and Determination Regarding Applicability of Certain Reasonable Further Progress and Attainment Demonstration Requirements: Direct Final Rule,'' 60 FR 30189, 30190 (June 8, 1995); and ''Determination of Attainment of Ozone Standard for Salt Lake and Davis Counties, Utah, and Determination Regarding Applicability of Certain Reasonable Further Progress and Attainment Demonstration Requirements: Final Rule,'' 60 FR 36723, 36724 (July 18, 1995). The EPA's interpretation was upheld by the Court of Appeals for the 10th Circuit, in *Sierra Club* v. *EPA*, 99 F.3d 1551, 1557 (10th Cir. 1996).

Accordingly, EPA believes it clear that the reference in section 110(a)(2)(D)(i)(I) to ''nonattainment'' refers to air quality, not designation status. The EPA believes this matter is clearly resolved by reference to the terms of the provision itself, so that under the first step of the *Chevron* analysis, no further inquiry is needed. If, however, it were concluded that the provision is ambiguous on this point, then EPA believes that, under the second step in the *Chevron* analysis, EPA should be given deference for any reasonable interpretation. Interpreting ''nonattainment'' to refer to air quality is reasonable for the reasons described above.[19]

The structure of the schedules for requiring SIP submissions and designating areas nonattainment provides support for EPA's interpretation. As noted above, section 110(a)(1) requires States to submit SIPs covering all their areas—regardless of whether designated, or how designated— within 3 years of a NAAQS revision and requires that those SIPs include provisions meeting the requirements of section 110(a)(2)(D).[20] When a new or revised NAAQS is promulgated, section 107(d)(1) authorizes a process of up to 3 years for designations. States must recommend designations within one year of promulgation of a new or revised NAAQS and EPA must designate areas within 2 years of promulgation; EPA may take up to 3 years to designate areas if insufficient information prevents designations within 2 years. In the case of the 8-hour ozone NAAQS, Congress provided specific legislation for designations (Pub. L. 105–178 § 6103). Under this new legislation, States are provided 2 years to make recommendations and EPA must designate areas within 1 year of the time State recommendations are due. Because of this legislation, designations must occur 3 years following promulgation of the NAAQS (July 2000). The EPA believes that it is not sensible to interpret the term ''nonattainment'' in section 110(a)(2)(D)(i)(I) to refer to nonattainment designations because those designations may not be made until 3 years after the promulgation of a new or revised NAAQS, and the section 110(a)(2)(D) submittals are due within 3 years.

Further, interpreting the reference to ''nonattainment'' as a reference to air quality, and not designation, is consistent with the air quality goals of section 110(a)(2)(D) and the CAA as a whole. In the present case, it is clear from air quality monitoring and modeling that large areas of the eastern part of the United States are in violation of the 8-hour NAAQS, and it is also clear from air quality modeling studies that NO_X emissions from sources in upwind States contribute to those air quality violations. The EPA currently has available all the information that it needs to determine whether upwind States should be required to revise their SIPs to implement appropriate reductions in NO_X emissions. The designation process will clarify the precise boundaries of the downwind areas, but because ozone is a regional phenomenon, information as to the precise boundaries of the downwind areas is not necessary to implement the requirements of section 110(a)(2)(D)(i). As a result, no air quality purpose will be served by waiting until the downwind areas are designated nonattainment.

On the contrary, taking action now is necessary to protect public health. As described in Section I.G., the regional NO_X reductions required under today's action will allow numerous areas currently in violation of the 8-hour NAAQS to attain that standard. For the millions of people living in those areas, today's action will advance the date by which these areas will meet the revised ozone standard. Taking action now is particularly important because one of the sub-population groups at higher risk to ozone health effects is children who are active and spend more time outdoors during the summer months when ozone levels are elevated.

(3) EPA's Authority to Require Section 110(a)(2)(D) Submissions in Accordance with section 110(a)(1). Commenters argue that sections 110(a)(1), (a)(2), and 172(b) should be read so that only requirements under section 110(a)(2) that are unrelated to nonattainment are due under the section 110(a)(1) timetable. These commenters contend that requirements under section 110(a)(2) that are related to nonattainment—including section 110(a)(2)(D)—are due under the section 172(b) timetable, that is, within 3 years of the designation of areas as nonattainment. In support, these commenters rely on language in section 110(a)(1) indicating that the submissions are for plans for air quality regions ''within such State.'' Finally, certain commenters cite as further support for their position the definition of the term ''nonattainment'' as found in section 107(d)(1)(A), claiming that the definition includes interstate transport areas.

As noted above, section 110(a)(1) provides that States must submit SIP revisions providing ''for the implementation, maintenance and enforcement'' of the NAAQS in each area of the State within 3 years (or a shorter time prescribed by the Administrator) following promulgation of a new or revised NAAQS. Section 110(a)(2) then sets forth the applicable elements of a SIP. These provisions apply to all areas within the State, regardless of designation. Section 172(b) establishes a SIP submission schedule for nonattainment areas. It provides that at the time EPA designates areas as nonattainment, EPA shall establish a SIP submission schedule for the submission of a SIP meeting the requirements of section 172(c).

While EPA agrees that there is overlap between the submission requirements under sections 110(a)(1)–(2) and 172(c), EPA believes that the plain language of section 110(a)(1)–(2) authorizes EPA to require the section 110(a)(2)(D) SIPs on the schedule described today, and that there is nothing to the contrary in section 172. Sections 110(a)(2) and 172 contain cross-references to each other.[21]

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[19] Similarly, EPA believes that the term ''maintenance'' in another clause of section 110(a)(2)(D)(i)(I) refers to air quality status as well. This clause includes only the term ''maintenance,'' and does not include the term ''area.''

[20] See ''Re-issue of the Early Planning Guidance for the Revised Ozone and Particulate Matter (PM) National Ambient Air Quality Standards (NAAQS),'' memorandum from Sally L. Shaver, dated June 16, 1998.

[21] Section 110(a)(2)(D) provides that areas designated nonattainment must submit SIPs in accordance with ''part D'' (which includes section 172). Section 172(b) requires EPA to establish a schedule for designated nonattainment areas to meet the requirements of sections 172(c) and

These cross-references indicate that under certain circumstances, the section 110(a)(2)(D) submittal may be required under section 110(a)(1); and under other circumstances, the section 110(a)(2)(D) submittal may be required under section 172(b). These cross-references are particularly relevant with respect to nonattainment areas, which are subject to both sections 110(a) (1) and (2) and 172. In the current situation, EPA believes that it is appropriate to require the submissions to meet section 110(a)(2)(D) in accordance with the schedule in section 110(a)(1) rather than under the schedule for nonattainment areas in section 172(b).[22]

The EPA has provided that, for the revised ozone and particulate matter NAAQS, States must assess their section 110 SIPs by July 18, 2000 to ensure that they adequately provide for implementing the revised standards. See Re-issue of the Early Planning Guidance for the Revised Ozone and Particulate Matter (PM) National Ambient Air Quality Standards (NAAQS), memorandum from Sally L. Shaver, dated June 16, 1998. The EPA recognized that the section 110 SIP should generally be sufficient to address the revised NAAQS. However, the Agency noted three areas that the States particularly needed to assess, including whether the SIP adequately addressed section 110(a)(2)(D). The EPA also provided that the States should submit revisions to address section 110(a)(2)(D) on the timeframe established by the final NO_X SIP call, when issued. The submittal date that EPA has specified in the final NO_X SIP call rule is consistent with both the Early Planning Guidance and with section 110(a)(1) and (2) of the CAA.

The EPA acknowledges that it has not historically required an affirmative submission under section 110(a)(2)(D), applicable to specific sources of emissions, in response to the promulgation of a new or revised NAAQS. In part, this is because sufficient technical information was not available to determine which sources ''contribute significantly'' to nonattainment in a downwind area. In the absence of such a determination, States were unable to regulate sources under this provision in any meaningful way. However, based on the many analyses performed over the last several years, EPA believes that there is now affirmative information regarding significant contribution to ozone violations in the eastern portion of the country; in light of that evidence, it would not be appropriate to defer action under section 110(a)(2)(D) until a later time.

Moreover, as noted above, the section 172(c) SIP submissions apply only to areas designated nonattainment. Specifically, section 172(b) provides that ''[a]t the time'' EPA designates an area as nonattainment, EPA shall set a schedule ''according to which the State containing such area shall submit'' SIPs. Section 171(2) provides further clarification by providing that for purposes of part D of title I of the CAA (CAA sections 171–193) ''[t]he term 'nonattainment area' means, for any air pollutant, an area which is designated 'nonattainment' with respect to that pollutant within the meaning of section 107(d).'' By its terms then, section 172 does not apply to areas designated attainment or unclassifiable (even if such areas are not attaining the standard) or for areas not yet designated. Thus, section 110(a)(1) provides the only submission schedule for areas not designated nonattainment. For those areas, the commenters' argument that section 172(b) should establish the timetable for section 110(a)(2)(D)(i) SIPs clearly fails. Since certain portions of the 23 jurisdictions covered by this rule likely will not be designated nonattainment for the 8-hour standard, EPA believes that the section 110(a)(1) schedule is the only schedule (and thus is the reasonable schedule) to follow for purposes of the SIP call.

Furthermore, contrary to the commenters' assertions, the definition of nonattainment does not broadly include areas that contribute to nonattainment in a downwind State. The definition of nonattainment includes areas that have monitored violations of the standard and areas that ''contribute to ambient air quality in a nearby area'' that is violating the standard (section 107(d)(1)(A)(i) (emphasis added)). Thus, only ''nearby'' areas that contribute to violations of a standard will be included in the nonattainment designation; areas contributing to longer-range transport will not be designated nonattainment based solely on that longer-range transport. Therefore, they will not be subject to section 172(c) requirements and timing.

The commenters argue that EPA's position that section 110(a)(1) governs the section 110(a)(2)(D) SIP submittal schedule leads to the absurd result that upwind areas will be required to submit SIPs dealing with their contribution to a nonattainment problem downwind before the downwind area will be required to submit SIPs under section 172(b). The commenters explain that section 110(a)(2) requires SIP submittals on a faster timetable (within 3 years from the date of promulgation or revision of a NAAQS) than section 172(b) (within 3 years from the date of designation as nonattainment). The commenters also contend that section 107 provides that States have the primary responsibility for ensuring attainment within their boundaries; only after a State implements all statutorily required and necessary measures can it pursue reductions in other areas through a SIP call or section 126. The commenters contend that the SIP call is contrary to the plain language of section 107 and congressional intent because it would require upwind areas to implement controls before the downwind area has implemented all statutorily required or necessary controls.

While it is true that plans to meet the emissions budget for the SIP call will be due prior to nonattainment designations and attainment plans for areas designated nonattainment for the 8-hour standard, EPA does not consider this result to be absurd in the present case.

The CAA, at least since its amendment in 1970, has required States to regulate ozone. For more than the past 25 years, States have focused on the adoption and implementation of local controls for the purpose of bringing nonattainment areas into attainment. Thus, historically, the downwind nonattainment areas have borne the brunt of the control obligations through the implementation of local controls. In comparison, areas in attainment of the NAAQS, but upwind of nonattainment areas, have not been required to implement controls designed to ameliorate the air quality problems experienced by their downwind neighbors.

Since the CAA Amendment of 1977, designated nonattainment areas have been subject to specific local control obligations, such as vehicle I/M and, for stationary sources, the requirement to implement RACT. The CAA Amendments of 1990 tightened these control obligations for many areas. Moderate, serious, severe and extreme areas were required to reduce emissions by 15 percent between 1990 and 1996. In addition, each serious, severe and extreme area is required to achieve 9 percent reductions over the succeeding 3 year periods until the area attains the

110(a)(2); section 172(c)(7) requires that nonattainment SIPs shall meet the requirements of section 110(a)(2).

[22] In other situations, EPA has indicated that certain elements of section 110(a)(2) would be better addressed in accordance with the timeframe established in section 172. See e.g., 60 FR 12492, 12505 (March 7, 1995) Proposed Requirements for Implementation Plans and Ambient Air Quality Surveillance for Sulfur Oxides (Sulfur Dioxide) National Ambient Air Quality Standard.

standard. Additional requirements, such as the use of RFG and the use of vapor recovery devices on gasoline pumps, are also required for certain areas (see generally, CAA section 182 and, e.g., section 211(k)). Thus, downwind areas with nonattainment problems under the 1-hour NAAQS are under current obligations to submit SIP revisions containing local control measures for that standard. For these areas, local reductions needed to meet the 1-hour standard are already occurring and will be achieved prior to or on the same schedule as reductions States may require in response to the SIP call.

Furthermore, in many of the downwind areas, States have been taking action to reduce ozone levels for many years in order to meet the 1-hour ozone NAAQS. Although the fact that the 8-hour ozone NAAQS is a new form of the ozone standard, however, should not obscure the fact that the downwind States have been making efforts to reduce ozone levels for decades. The EPA believes that the history of implementation by downwind areas of ozone pollution controls further mitigates the commenters' argument that it is absurd to require upwind areas to implement controls in advance of downwind attainment demonstrations under the 8-hour NAAQS.[23]

Moreover, virtually all of the downwind States affected by today's rulemaking, due to 8-hour ozone nonattainment or maintenance problems, are themselves upwind contributors to problems further downwind, and, thus, are subject to the same requirements as the States further upwind.[24] The reductions these downwind States must implement due to their additional role as upwind States will help reduce their own 8-hour ozone problems on the same schedule as emissions reductions for the upwind States. Accordingly, for the most part, this rulemaking does not require upwind areas to take action in advance of any action by downwind areas to ameliorate the downwind problems.

Finally, even if EPA were requiring upwind States to take action to reduce downwind nonattainment and maintenance in advance of action by the downwind States, this would simply require upwind areas to take the first step by developing SIPs to eliminate their significant contribution to the downwind problem. The downwind areas will be required to take the next step by developing SIPs that address their share. Generally, an agency may resolve a problem (in this case, downwind nonattainment) on a step-by-step basis (see e.g., *Group Against Smog and Pollution, Inc.* v. *EPA*, 665 F.2d 1284, 1291–92 (D.C. Cir. 1981)).

A commenter has observed that under section 110(a)(1), EPA may authorize section 110(a)(2) submittals as late as 3 years after revision of a NAAQS, which, in this case, would run until July 2000. The Early Planning Guidance, described above, indicates that States are allowed until July 2000 to make submissions concerning other elements of section 110(a)(2). However, as described elsewhere, EPA has determined that the section 110(a)(2)(D) submittals should be submitted by the end of September 1999 to assure that the required NO_X reductions will be implemented as expeditiously as practicable, which EPA has determined is no later than the May 1 start of the 2003 ozone season (see Section V, below).

Citing section 107(a) of the CAA, the commenters assert that the CAA requires downwind areas to fully adopt and implement all statutorily required or necessary measures before EPA can require upwind areas to control emissions. Section 107 provides that States shall have the primary responsibility for assuring air quality within the State by submitting a plan that specifies how the NAAQS will be achieved and maintained in the State. The commenters attempt to read this statement regarding a State's authority to choose the mix of control measures within State boundaries as barring the control of emissions from upwind States.

This provision may be read as focusing on the State-Federal balance in controlling criteria pollutants, such as ozone, not any upwind-State, downwind-State balance. The provision indicates that although EPA may promulgate Federal measures that provide reductions to help States reach attainment, States bear the ultimate responsibility for assuring attainment. Further, this provision may be read to indicate that States may choose the mix of controls to reach attainment within their own boundaries. Nothing in this provision purports to address the need for upwind controls. By comparison, section 110(a)(2)(D) affirmatively requires States to submit a SIP prohibiting emissions that significantly contribute to downwind nonattainment or interfere with maintenance of the NAAQS. Thus, the statute, read as a whole, contemplates that interstate transport will be addressed as part of the downwind States' attainment responsibilities. Indeed, determining the upwind area's share of the problem is necessary in order for downwind attainment planning. In the absence of the upwind reductions that will be achieved, the downwind area would be required to submit an attainment plan to demonstrate attainment regardless of cost and without benefit of the reduction of upwind emissions that significantly contribute to nonattainment. In light of the statute as a whole, it is absurd to argue that Congress intended downwind areas to reduce emissions at any cost while upwind sources that significantly contribute to that nonattainment remain unregulated. Congress attempted to balance responsibilities, providing that States could choose the mix of controls within the State's borders (CAA section 107(a)) and are ultimately responsible for assuring attainment, but also recognizing that emissions reductions from upwind States may be needed for attainment (CAA section 110(a)(2)(D)(i)).

b. Process for Requiring SIP Submissions under the 8-Hour Standard. The time by which the section 110(a)(2)(D) SIP revision under the 8-hour NAAQS must be submitted is governed by section 110(a)(1), which requires the SIP revision to be ''adopt[ed] and submit[ed] to the Administrator, within 3 years (or such shorter period as the Administrator may prescribe) after the promulgation of a [NAAQS] (or any revision thereof) . . . .'' In the NPR, EPA indicated that the SIP revision would be due by the end of September 1999, which EPA expected to be 12 months from the date of completing today's final rule. In today's action, EPA is confirming that the SIP revision will be due September 30, 1999, for the reasons described below in Section VI.A.1, Schedule for SIP Revision.

3. Requirements of Section 110(a)(2)(D)

a. Summary. Today's action is driven by the requirements of CAA section 110(a)(2)(D). This provides that each SIP must—

[23] Although the SIP call will provide a benefit to a wide number of areas, the focus of the SIP call is to reduce boundary conditions for a number of areas that will have difficulty attaining either the 1-hour or 8-hour standard (or both) without the benefit of reductions from outside the nonattainment area. Based on current monitoring data and modeling, EPA predicts that there will be a number of areas that are meeting the 1-hour standard that will be designated nonattainment for the 8-hour standard. The EPA further predicts that many of these areas will come back into attainment due solely to the emission reductions achieved by the NO_X SIP call. However, this incidental benefit—which likely will occur without the need for local emission reductions—does not preclude EPA from requiring the SIP call reductions, which are needed to help other more seriously polluted areas that have long-standing pollution problems.

[24] Maine, New Hampshire, and Vermont are the only downwind States that are not subject to today's action.

* * * contain adequate provisions—(I) prohibiting, consistent with the provisions of this title, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—(I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard * * *

According to section 110(a)(2)(D), the SIP for each area, regardless of its designation as nonattainment or attainment (including unclassifiable), must prohibit sources within the area from emitting air pollutants in amounts that will ''contribute significantly'' to ''nonattainment'' in a downwind State, or that ''interfere with maintenance'' in a downwind State.

b. Determination of Meaning of ''Nonattainment'' (1) Geographic Scope. In determining the meaning and scope of section 110(a)(2)(D), it is useful first to determine the geographic scope of ''nonattainment'' downwind.

At proposal, EPA stated that it—

* * * proposes to interpret this term to refer to air quality and not to be limited to currently-designated nonattainment areas. Section 110(a)(2)(D) does not refer to ''nonattainment areas,'' which is a phrase that EPA interprets to refer to areas that are designated nonattainment under * * * section 107(d)(1)(A)(I) * * * . Rather, the provision includes only the term 'nonattainment' and does not define that term. Under these circumstances, EPA has discretion to give the term a reasonable definition, and EPA proposes to define it to include areas whose air quality currently violates the NAAQS, and will likely continue [to violate in the future], regardless of the designation of those areas * * *

(62 FR 60324).

To determine whether areas would continue to violate in the future, EPA proposed to take into account the reductions that would result from current CAA control requirements (apart from controls that may be required under section 110(a)(2)(D)). To take these reductions into account, EPA determined whether the area would be in nonattainment in the future based on air quality modeling that assumed CAA-mandated reductions and that accounted for growth. If an area would reach attainment based on required controls, EPA would not view that area as having a nonattainment problem to which any upwind areas may be considered to contribute.

As explained earlier, in today's action, EPA has determined that for purposes of the 8-hour NAAQS, the reference to ''nonattainment'' should be defined as EPA proposed. Thus, in determining whether an upwind area contributes significantly to ''nonattainment'' downwind, EPA would evaluate downwind areas for which monitors indicate current nonattainment, and air quality models indicate future nonattainment, taking into account CAA control requirements and growth.

For the 1-hour standard, EPA proposed to define nonattainment to include all grid cells within a county when a monitor in that county indicated nonattainment. Upon further study, EPA found that in some instances, a metropolitan area may consist of numerous counties, only a few of which contain monitors indicating nonattainment. The EPA recognizes that under the 1-hour NAAQS, nonattainment boundaries are generally used to describe the area with the nonattainment problem; accordingly, EPA believes that this geographic vicinity offers an appropriate indication of an area that may be expected to have nonattainment air quality. The EPA predicts that many 1-hour nonattainment areas that currently monitor nonattainment somewhere within the area will remain in nonattainment in 2007, in some cases because of predicted violations in counties that currently monitor attainment. The EPA believes that the entire area should be considered to be in nonattainment until all monitors in the area indicate attainment of the NAAQS. Thus, in today's action, EPA used the designated nonattainment area in determining the downwind nonattainment problem.[25]

As noted above, commenters disagreed with EPA's view that the term ''nonattainment'' covers areas with air quality that is currently in nonattainment, regardless of designation. The EPA's response to those comments is also set forth above.

(2) 2007 Projection Year. In the NPR, EPA indicated that it would adopt the year 2007 as the year for determining whether areas achieved their required NO_X budget levels. Accordingly, in determining whether downwind areas should be considered to be, and remain in, ''nonattainment,'' EPA would model their air quality in 2007, based on the implementation of CAA required controls by that date, and growth in emissions—generally due to economic growth and greater use of vehicles—by that date. At proposal, EPA adopted this same approach with respect to both the 1-hour and the 8-hour NAAQS (62 FR 60325). The EPA is continuing this approach.

c. Definition of Significant Contribution. As indicated in the NPR, neither the CAA nor its legislative history provides meaningful guidance for interpreting the term ''contribute significantly'' under section 110(a)(2)(D)(i)(I).

(1) ''Contribute.'' The initial step in defining the ''contribute significantly'' term is to determine the meaning of the term ''contribute.'' In the NPR, EPA stated that it believes this term should be defined broadly, so that emissions ''contribute'' to nonattainment downwind if they have an impact on nonattainment downwind (62 FR 60325). Air quality modeling indicated that emissions from the upwind States clearly impact downwind nonattainment problems; as a result, EPA generally folded this step of determining whether sources ''contribute'' to nonattainment downwind into the step of determining whether that contribution is ''significant,'' discussed below.

In addition, section 110(a)(2)(D)(i)(I) requires the SIP to prohibit amounts of emissions ''which *will* contribute significantly * * *'' (emphasis added). The EPA believes that the term ''will'' means that SIPs are required to eliminate the appropriate amounts of emissions that presently, or that are expected in the future, contribute significantly to nonattainment downwind.

Because ozone is a secondary pollutant formed as a result of complex chemical reactions involving numerous sources, it is not possible to determine the downwind impact on each individual source. In addition, ozone generally results from the contributions of numerous sources. As indicated in the NPR:

[U]nhealthful levels of ozone result from emissions of NO_X and VOCs from thousands of stationary sources and millions of mobile sources [and consumer products and other sources] across a broad geographic area. Each source's contribution is a small percentage of the overall problem; indeed, it is rare for emissions from even the largest single sources to exceed one percent of the inventory of ozone precursors even for a single metropolitan area. Under these circumstances, even complete elimination of any given source's emissions may well have no measurable impact in ameliorating the nonattainment problem. Rather, attainment requires controls on numerous sources across a broad area. Ozone is a regional scale

[25] It should be reiterated that EPA relied on the designated area solely as a proxy to determine which areas have air quality in nonattainment. This proxy is readily available under the 1-hour NAAQS because areas have long been designated nonattainment. The EPA's reliance on designated nonattainment areas for purposes of the 1-hour NAAQS does not indicate that the reference in section 110(a)(2)(D)(i)(I) to ''nonattainment'' should be interpreted to refer to areas designated nonattainment.

problem that requires regional scale reductions

(62 FR 60326).

Accordingly, EPA has adopted a ''collective contribution'' approach to determining whether sources ''contribute'' to nonattainment downwind: EPA determines the impact downwind of emissions in the aggregate from a particular geographic region. If the aggregated emissions are considered to contribute to nonattainment downwind, then all of the emissions in that region should be considered as contributors to that nonattainment problem. In today's action, EPA is continuing the same interpretation of the term ''contribute,'' for the reasons just described.

(2) ''Significantly''. (a) Notice of Proposed Rulemaking. In the NPR, EPA proposed a ''weight-of-evidence,'' or multi-factor, approach for determining whether a contribution is ''significant.''

The EPA proposed two separate interpretations for the term ''contribute significantly,'' which had implications as to which factors were to be considered in what parts of the analysis. Under the first interpretation, significant contribution is determined with reference to—

> * * * factors concerning amounts of emissions and their ambient impact, including the nature of how the pollutant is formed, the level of emissions and emissions density (defined as amount of emissions per square mile) in the particular upwind area, the level of emissions in other upwind areas, the amount of contribution to ozone in the downwind area from the upwind areas, and the distance between the upwind sources and the downwind nonattainment problem. Under this approach, when emissions and ambient impact reach a certain level, as assessed by reference to the factors identified above, those emissions would be considered to ''contribute significantly'' to nonattainment.

(62 FR 60325).

Under this interpretation, after identifying amounts of emissions that constitute a significant contribution, EPA then determines the amount of emissions reductions necessary to adequately mitigate these contributions. This determination entails—

> * * * [e]valuation of the costs of available measures for reducing upwind emissions * * * as well as to the extent known (at least qualitatively), the relative costs of, amounts of reductions from, and ambient impact of measures available in the downwind areas.

Id.

Under the second interpretation, EPA considers all of the factors under both the significant contribution prong and the mitigation prong of the first interpretation, and, once EPA determines an amount of emissions that does significantly contribute to downwind nonattainment, then EPA would determine that the SIP must contain provisions adequate to prohibit that amount of emissions. Id. at 60325–26.

(b) Today's Action. The EPA has determined that the second interpretation should be used; that is, that the determination of significant contribution includes both air quality factors relating to amounts of upwind emissions and their ambient impact downwind, as well as cost factors relating to the costs of the upwind emissions reductions. Once an amount of emissions is identified in an upwind State that contributes significantly to a nonattainment problem downwind, or interferes with maintenance downwind, the SIP must include provisions to eliminate that amount of emissions.

To reiterate, section 110(a)(2)(D)(i)(I) provides that the SIP must ''prohibit[]'' sources from ''emitting any air pollutant in amounts which will contribute significantly to nonattainment in, or interfere with maintenance by, any other State.'' The term ''prohibit'' is defined as ''to forbid by authority'' or ''prevent,'' or ''preclude.'' ''The American Heritage Dictionary of the English Language'' (3d ed. 1992, 1448). The EPA believes that the term ''prohibit'' means that SIPs must eliminate those amounts of emissions determined to contribute significantly to nonattainment or interfere with maintenance downwind. Moreover, EPA believes that whether emissions ''contribute significantly'' depends on a multifactor test, as described below. Thus, section 110(a)(2)(D)(i)(I) does not require the elimination of all upwind source emissions that impact downwind air quality problems, but only those amounts of emissions that, based on a multi-factor test, significantly contribute to downwind air quality problems.

d. Multi-factor Test for Determining Significant Contribution. In the NPR, EPA proposed a multi-factor test for determining whether emissions from an upwind State contribute significantly to a nonattainment or maintenance problem downwind. The EPA received numerous comments on the factors. Based on the comments and EPA's further analysis, EPA, in today's action, is continuing the multi-factor approach, with some refinements in response to comments, with respect to the factors EPA considered and the manner in which EPA considered them.

In determining whether emissions from upwind States affected by today's action contribute significantly to downwind nonattainment or maintenance problems, EPA specifically considered the following factors with respect to each such upwind State. These factors were the primary components in EPA's consideration.

► The overall nature of the ozone problem (i.e., ''collective contribution'')

► The extent of the downwind nonattainment problems to which the upwind State's emissions are linked, including the ambient impact of controls required under the CAA or otherwise implemented in the downwind areas

► The ambient impact of the emissions from the upwind State's sources on the downwind nonattainment problems

► The availability of highly cost effective control measures for upwind emissions.

The first three of these factors are related to air quality; the fourth is related to costs.

In addition, EPA generally reviewed several other considerations before concluding that upwind emissions contribute significantly to downwind nonattainment. The EPA did not consider it necessary, or did not have adequate information, to apply each of these factors with specificity with respect to each upwind State's emissions. In addition, in some instances, EPA did not have quantitative information to assess certain of these factors, and instead relied on qualitative information. These considerations were secondary aspects of EPA's analysis. They include:

► The consistency of the regional reductions with the attainment needs of the downwind areas with nonattainment problems

► The overall fairness of the control regimes required of the downwind and upwind areas, including the extent of the controls required or implemented by the downwind and upwind areas

► General cost considerations, including the relative cost-effectiveness of additional downwind controls compared to upwind controls

All of these factors and considerations are described in the following sections.

e. Air Quality Factors. As noted above, EPA specifically considered three air quality factors with respect to each upwind State, which factors, in conjunction with the cost factor discussed in the next section, were the primary components in EPA's consideration:

► The overall nature of the ozone problem (*i.e.*, ''collective contribution'')

► The extent of the downwind nonattainment problems to which the upwind State's emissions are linked, including the ambient impact of controls required under the CAA or otherwise implemented in the downwind areas

► The ambient impact of the emissions from the upwind State's sources on the downwind nonattainment problems

(1) Collective Contribution. As indicated elsewhere, ozone generally results from the collective contribution of emissions from numerous sources over a large geographic area. For example, for urban nonattainment areas under the 1-hour NAAQS, the downwind sources, comprise numerous stationary sources as well as mobile on-road sources, mobile off-road sources, and consumer and commercial products. Further, additional contributions are made by numerous upwind States, both adjacent to and further away from the nonattainment area itself. The fact that virtually every nonattainment problem is caused by numerous sources over a wide geographic area is a factor suggesting that the solution to the problem is the implementation over a wide area of controls on many sources, each of which may have a small or unmeasureable ambient impact by itself.

(2) Extent of Downwind Nonattainment Problems, Including Ambient Impact of Required Controls. In determining whether a downwind area has a nonattainment problem under the 1-hour standard to which an upwind area may be determined to be a significant contributor, EPA determined whether the downwind area currently has a nonattainment problem, and whether that area area would continue to have a nonattainment problem as of the year 2007 assuming that in that area, all controls specifically required under the CAA were implemented, and all required or otherwise expected Federal measures were implemented. If, following implementation of such required CAA controls and Federal measures, the downwind area would remain in nonattainment, then EPA considered that area as having a nonattainment problem to which upwind areas may be determined to be significant contributors.

Thus, this analytical approach assumes that downwind areas implement all required controls and receive the benefit of reductions from Federal measures, and yet have a residual nonattainment problem (prior to the implementation of the regional reductions required by today's action). The fact that a nonattainment problem persists, notwithstanding fulfillment of CAA requirements by the downwind sources, is a factor suggesting that it is reasonable for the upwind sources to be part of the solution to the ongoing nonattainment problem.

The EPA undertook a comparable analysis with respect to the 8-hour NAAQS. That is, the major urban areas in the northeast, midwest, and south that are violating the 8-hour NAAQS are designated nonattainment under the 1-hour NAAQS as well. After these areas are designated nonattainment under the 8-hour NAAQS, they will become subject to the control requirements of section 172(c). However, for these areas, the section 172(c) requirements do not, by their terms, impose any specific controls other than what these areas have already implemented to fulfill the requirements under section 182 attendant to their designation and classification under the 1-hour NAAQS. Accordingly, the same air quality modeling analyses that shows residual nonattainment for at least one of the urban areas linked to each upwind State under the 1-hour standard shows residual nonattainment for those areas under the 8-hour NAAQS. Indeed, modeling analyses relied on for today's action indicate residual nonattainment for the major urban areas even after the implementation of regional reductions comparable to those required today.[26]

(3) *Ambient Impact of Emissions from the Upwind Sources.* In today's action, EPA examined the impact of numerous upwind States on numerous downwind areas with nonattainment problems.

Under the 1-hour NAAQS, EPA conducted various air quality modeling analyses that examined the impact of emissions from sources in each upwind State on ozone levels in downwind nonattainment areas, in light of the impact of emissions from sources in other upwind States on the downwind area's nonattainment problem. The EPA assessed the frequency and magnitude of each upwind State's contribution to downwind nonattainment problems. Some of the modeling analyses also permitted determining the magnitude of the average contribution and the peak contribution from each upwind State, as well as the percentage of each upwind State's contribution to the downwind nonattainment problem.

[26] The presence of residual nonattainment in major urban areas after their implementation of specifically required CAA controls supports the regional reductions required under today's action. Those regional reductions allow the major urban areas to progress towards attainment under the 8-hour NAAQS, and, at the same time, significantly ameliorate the nonattainment problems under the 8-hour NAAQS for numerous other areas. In fact, EPA projections indicate that numerous areas with nonattainment problems will achieve attainment of the 8-hour NAAQS as a result of the regional reductions.

The EPA determined that for each upwind State affected by today's action, its contribution to a downwind nonattainment problem, in conjunction with the contribution from other upwind States, comprised a relatively large percentage of the nonattainment problem. The EPA further determined that, in this context, the impacts from each affected upwind State's NO_X emissions are sufficiently large and/or frequent so that the amounts of that State's emissions should be considered to be significant contributions, depending on the cost factor and other relevant considerations. For most upwind States, EPA conducted two types of modeling—UAM–V and CAMx—that isolated the impact of emissions from the upwind State alone on downwind nonattainment.

The EPA also conducted much the same analysis to determine the impact of emissions from each upwind State on ozone levels in downwind States under the 8-hour NAAQS. Because nonattainment problems under the 8-hour NAAQS are widespread, and because EPA has not designated individual nonattainment areas, EPA focused this part of its inquiry on the upwind State's impact on the entire downwind State.

The EPA's analysis under both the 1-hour and 8-hour NAAQS led EPA to conclude that, in light of both the collective contribution nature of the ozone problem, and the fact that downwind areas continue to suffer a nonattainment problem even after implementation of all required CAA measures and Federal measures, emissions from each of the affected upwind States have a sufficiently large and/or frequent ambient impact such that those emissions contribute significantly to nonattainment downwind, depending on the availability of highly cost-effective measures and on other considerations discussed below.

f. Determination of Highly Cost-effective Reductions and of Budgets. After determining the degree to which NO_X emissions, as a whole from the particular upwind States, contribute to downwind nonattainment or maintenance problems, EPA then determined whether any amounts of the NO_X emissions may be eliminated through controls that, on a cost-per-ton basis, may be considered to be highly cost effective. By examining the cost effectiveness of recently promulgated or proposed NO_X controls, EPA determined that an average of approximately $2,000 per ton removed is highly cost effective. The EPA then determined a set of controls on NO_X sources that would cost no more than an average of $2,000 per ton reduced. Specifically, EPA determined that one set of these controls would include a cap-and-trade program for (i) electricity generating boilers and turbines larger than 25 Mwe (''large EGUs''), and (ii) large non-electricity generating industrial boilers and turbines (''large non-EGU boilers and turbines''). The application of an emission rate of 0.15 lb/mmBtu and 1995–1996 utilization for EGUs and 60 percent for large non-EGUs to the emissions projected to occur in 2007 including growth and CAA measures, led to the determination of the amounts to be reduced. The remaining amount is a State's budget.

The EPA further determined that additional highly cost-effective controls are also available for cement manufacturing sources and internal combustion engines. On the basis of reasonable assumptions concerning growth to the year 2007, EPA then determined the amounts of emissions from these source categories that would be eliminated with those controls.

The EPA further determined that there were no other controls on other NO_X sources that qualify as highly cost effective (although several controls are reasonably cost-effective).

On the basis of the determinations just described for the various source categories, EPA determined an amount of NO_X emissions that may be eliminated through these highly cost-effective measures. Because EPA had also determined that the NO_X emissions from the affected upwind States have a large and/or frequent impact on downwind nonattainment or maintenance problems, EPA concludes that the amount of NO_X emissions from those States that can be eliminated through application of highly cost-effective control measures contributes significantly to nonattainment or maintenance problems downwind.

Under section 110(a)(2)(D)(i)(I), the SIP must include ''adequate provisions prohibiting'' sources from emitting these ''amounts.'' Because no highly cost-effective controls are available to eliminate the remaining amounts of NO_X emissions, EPA concludes that those emissions do not contribute significantly to downwind nonattainment or maintenance problems. As indicated below and in Section III, there are cost-effective alternatives available to States that choose not to adopt all of the highly cost-effective measures on which EPA based its selection of the significant amounts of NO_X emissions.

To implement EPA's determinations, each affected upwind State is required to submit for EPA approval SIP controls projected to be sufficient, by the year 2007, to eliminate the amount of NO_X emissions in the State that EPA determined contributes significantly to nonattainment. The EPA determined this amount of reductions, for each affected upwind State, as follows: EPA first determined the amount of NO_X emissions in that State by the year 2007, based on assumptions concerning both growth and emissions controls that are required under the CAA or that will be implemented due to Federal actions (the ''2007 base case''). Second, EPA applied the control measures identified as highly cost effective to the 2007 base case amount for the appropriate source categories. The amount of NO_X emissions remaining in the State after application of controls to the affected source categories constitutes the 2007 budget. The difference between the 2007 base case and the 2007 budget is the amount of NO_X emissions in that State by the year 2007 that EPA has determined to contribute significantly to nonattainment and that, therefore, the SIPs must prohibit.

The upwind State's SIP revision due in response to today's action must provide controls that, on the basis of the same assumptions (including concerning growth) made by EPA in determining the budget, would limit NO_X emissions in the year 2007 to no more than the 2007 budget. The State has full discretion in selecting the controls, so that it may choose any set of controls that would assure achievement of the budget.

As EPA stated in the NPR:

> States are not constrained to adopt measures that mirror the measures EPA used in calculating the budgets. In fact, EPA believes that many control measures not on the list relied upon to develop EPA's proposed budgets are reasonable—especially those, like enhanced vehicle inspection and maintenance programs, that yield both NO_X and VOC emissions reductions.[27] Thus, one State may choose to primarily achieve emissions reductions from stationary sources while another State may focus emission reductions from the mobile source sector.

(62 FR 60328).

The EPA believes that its overall approach derives further support from the mandate in section 110(a)(2)(D) that each SIP include provisions prohibiting ''any source or other type of emissions activity within the State from emitting any air pollutant in amounts' that adversely affect downwind areas. The phrase ''any source or other type of emissions activity'' may be interpreted to require that the SIP regulate all sources of emissions to assure that the total amount of emissions generated within the State does not adversely affect downwind areas. By its terms, the phrase covers all emitters of any kind because every emitter—stationary, mobile, or area—may be considered a ''source or other type of emissions activity.'' This interpretation is consistent with the legislative history of the phrase. Prior to the CAA Amendments of 1990, the predecessor to section 110(a)(2)(D), which was section 110(a)(2)(E), referred to ''any stationary source within the State.'' In the 1990 Amendments, Congress revised the phrase to read as it currently does. A Committee Report explained, ''Where prohibitions in existing section 110(a)(2)(E) apply only to emissions from a single source, the amendment includes ''any other type of emissions activity,'' which makes the provision effective in prohibiting emissions from, for example, multiple sources, mobile sources, and area sources.'' V Leg. Hist. 8361, S. Rep. No. 228, 101st Cong., 1st Sess. 21 (1989).

For reasons explained below, if an upwind State chooses to achieve all or a portion of the required reductions from large EGUs or large non-EGU boilers and turbines, then the SIP must include a mass emissions limitation for those sources computed with reference to certain growth assumptions and the emission rate limits chosen by the State. The EPA recommends that this mass limitation, or cap, be accompanied by a trading program. Any such cap-and-trade program must be established by May 1, 2003. If the State chooses to achieve all or a portion of the required reductions from other sources, then the State must implement controls, by the year 2003, on those other sources that are projected to achieve the required level of reductions, based on certain assumptions (including growth), in the year 2007. The controls on these other sources may be rate-based, and no emissions cap on them is required. By the year 2007, any applicable mass emissions limitation for large EGUs or large non-EGU boilers and turbines must continue to be met, and any applicable controls on other sources must continue to be implemented. The amount of the 2007 overall budget is used to compute the level of controls that would result in the appropriate amount of emissions reductions, given assumptions concerning, for example,

[27] As indicated in the NPR, EPA considers that measures may be reasonable in light of their reduction of VOC and NO_X emissions, even though their cost-effectiveness in terms of cost per NO_X emissions removed is relatively high (62 FR 60346–48).

growth. To this extent, the 2007 overall budget is an important accounting tool. However, the State is not required to demonstrate that it has limited its total NO_X emissions to the budget amounts. Thus, the overall budget amount is not an independently enforceable requirement.

g. Other Considerations in Determination of Significant Contribution. The EPA reviewed several other considerations in support of its determination that the specified amounts of emissions from the affected upwind States contribute significantly to nonattainment downwind.

(1) Consistency of Regional Reductions with Downwind Attainment Needs. The EPA conducted modeling analyses of emission reductions of virtually the same magnitude as the regional reductions required under today's action. Although the impact on any downwind ozone problem of each upwind State's emissions reductions alone may be relatively small, the impact of those reductions, when combined with the reductions from the other States, is substantial. Based on this modeling, EPA determined that the regional reductions allow downwind nonattainment areas under the 1-hour NAAQS to make appreciable progress towards attainment. The EPA further determined that under the 8-hour NAAQS, many areas with nonattainment problems are expected to reach attainment based solely on the regional reductions, and that other (primarily urban) areas would benefit from the regional reductions but are expected to experience residual nonattainment. EPA further determined that none of the upwind States affected by today's action are affected by ''overkill,'' that is, required reductions that are more than necessary to ameliorate downwind nonattainment in every downwind area affected by that upwind State.

(2) Fairness. The EPA also considered the overall fairness of the control regimes required of the downwind and upwind areas, including the extent of the controls required or implemented by the downwind and upwind areas. Most broadly, EPA believes that overall notions of fairness suggest that upwind sources which contribute significant amounts to the nonattainment problem should implement cost-effective reductions. When upwind emitters exacerbate their downwind neighbors' ozone nonattainment problems, and thereby visit upon their downwind neighbors additional health risks and potential clean-up costs, EPA considers it fair to require the upwind neighbors to reduce at least the portion of their emissions for which highly cost-effective controls are available.

In addition, EPA recognizes that in many instances, areas designated as nonattainment under the 1-hour NAAQS have incurred ozone control costs since the early 1970s. Moreover, virtually all components of their NOx and VOC inventories are subject to SIP-required or Federal controls designed to reduce ozone. Furthermore, these areas have complied with almost all of the specific control requirements under the CAA, and generally are moving towards compliance with their remaining obligations. The CAA's sanctions and FIP provisions provide assurance that these remaining controls will be implemented. By comparison, many upwind States in the midwest and south have had fewer nonattainment problems and have incurred fewer control obligations.

(3) General Cost Considerations. The EPA also considered the fact that in general, areas that currently have, or that in the past have had, nonattainment problems under the 1-hour NAAQS, or that are in the Northeast Ozone Transport Region (OTR), have already incurred ozone control costs. The controls already implemented in these areas tend to be among the less expensive of available controls. As described in more detail below, EPA has determined that, in general, the next set of controls identified as available in the downwind nonattainment areas under the 1-hour NAAQS would cost approximately $4,300 per ton removed. By comparison, EPA has determined that the cost of the regional reductions required today would approximate $1,500 per ton removed. Thus, it appears that the upwind reductions required by today's action are more cost-effective per ton removed than reductions in the downwind nonattainment areas. Moreover, under the 1-hour NAAQS, the reductions required from each upwind State, in conjunction with reductions from other upwind States, result in ambient improvement in at least several downwind areas with nonattainment problems.

The EPA did not have available, and was not presented with, meaningful quantitative information indicating the cost-effectiveness of the regional reductions required today in light of their ambient impact downwind (e.g., the cost of emissions reductions per ppb improvement in ambient ozone levels in a downwind nonattainment area). This lack of information limited the extent to which EPA could rely on this consideration in making its determinations.

The various considerations just discussed point in the same direction as the other factors described above concerning air quality and costs. These factors and considerations lead EPA to conclude that the amounts of each upwind State's emissions that may be eliminated through highly cost-effective measures contribute significantly to nonattainment or maintenance problems downwind.

h. Interfere with Maintenance. Once a nonattainment area has attained the NAAQS, it is required to maintain that standard (e.g., sections 107(d)(3)(E)(iv), 110(a)(1)). Section 110(a)(2)(D)(i)(I) also requires that SIPs contain adequate provisions prohibiting amounts of emissions that ''interfere with maintenance by * * * any [downwind] State.'' The EPA explained and applied this requirement in the NPR as follows:

> This [interfere-with-maintenance] requirement * * * does not, by its terms, incorporate the qualifier of ''significantly.'' Even so, EPA believes that for present purposes, the term ''interfere'' should be interpreted much the same as the term ''contribute significantly,'' that is, through the same weight-of-evidence approach.
>
> With respect to the 1-hour NAAQS, the ''interfere-with-maintenance'' prong appears to be inapplicable. The EPA has determined that the 1-hour NAAQS will no longer apply to an area after EPA has determined that the area has attained that NAAQS. Under these circumstances, emissions from an upwind area cannot interfere with maintenance of the 1-hour NAAQS.
>
> With respect to the 8-hour NAAQS, the ''interfere-with-maintenance'' prong remains important. After an area has reached attainment of the 8-hour NAAQS, that area is obligated to maintain that NAAQS. (See sections 110(a)(1) and 175A.) Emissions from sources in an upwind area may interfere with that maintenance.
>
> The EPA proposes to apply much the same approach in analyzing the first component of the ''interfere-with-maintenance'' issue, which is identifying the downwind areas whose maintenance of the NAAQS may suffer interference due to upwind emissions. The EPA has analyzed the ''interfere-with-maintenance'' issue for the 8-hour NAAQS by examining areas whose current air quality is monitored as attaining the 8-hour NAAQS [or which have no current air quality monitoring], but for which air quality modeling shows nonattainment in the year 2007. This result is projected to occur, notwithstanding the imposition of certain controls required under the CAA, because of projected increases in emissions due to growth in emissions generating activity. Under these circumstances, emissions from upwind areas may interfere with the downwind area's ability to attain. Ascertaining the impact on the downwind area's air quality of the upwind area's emissions aids in determining whether the upwind emissions interfere with maintenance

(62 FR 60326).

In today's action, EPA is taking the same positions with respect to the interfere-with-maintenance test as described in the NPR. Because EPA generally interprets the ''interfere-with-maintenance'' test the same as the ''contributes-significantly-to-nonattainment'' test, for purposes of convenience, in this final rule, EPA sometimes refers to ''contributes-significantly-to-nonattainment'' to refer to both tests.

i. Dates. In today's action, EPA is determining that SIP submissions required under this rulemaking must be submitted by September 30, 1999 (see Section VI.A.1, Schedule for SIP Revision).

Further, in today's action, EPA is requiring that SIP controls required today must be implemented by no later than May 1, 2003, and they must achieve reductions computed with reference to an overall budget amount determined as of September 30, 2007 (see Section V, NO_X Control Implementation and Budget Achievement Dates).

j. Downwind Areas' Control Obligations. Commenters have argued that under the CAA, downwind States must implement additional controls before EPA may require controls in upwind States. Commenters base this argument in part on the provisions of CAA section 107(a), which provides,

> Each State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State by submitting an implementation plan for such State which will specify the manner in which [NAAQS] will be achieved and maintained within each air quality control region in such State.

Commenters further note that downwind States must implement additional reductions (beyond those specifically required by the CAA[28]) as needed to attain, under section 182(b)(1)(A)(i) and 182(c)(2)(A). The commenters add that section 179(d)(2) is a generally applicable provision that limits the stringency of required controls to what is feasible. The commenters read these provisions together to conclude that downwind States must first implement all feasible control measures in an effort to reach attainment, and only after EPA determines that such States have done so but have not reached attainment may EPA require upwind contributors to implement controls. The commenters further observe that some of the downwind States in the Northeast have not implemented all feasible SIP measures.

The EPA disagrees with this legal analysis. The provision in section 107(a) that accords to States the primary responsibility for the air quality of their air basins, in essence provides the underlying rationale for the requirement of States to submit SIP revisions that meet CAA requirements. This phrase clarifies that the requirement of assuring attainment does not fall, in the first instance, on EPA. This provision does not have implications for apportioning responsibility between the downwind State and upwind States for contributions from upwind States. Downwind States would still carry the primary responsibility of assuring clean air even after the upwind contributors have revised their SIPs to meet the requirements of section 110(a)(2)(D).

Furthermore, EPA disagrees that section 179(d)(2) has any application to today's rulemaking. That provision in essence provides a general rule that if a nonattainment area fails to attain by its attainment date, EPA may require the State to implement reasonable controls that can be ''feasibly implemented.'' This requirement is not relevant to today's rulemaking, which addresses the requirements under section 110(a)(2)(D)(i)(I) that SIPs include provisions eliminating amounts of emissions from their sources that contribute significantly to downwind nonattainment.

In addition, the requirement of downwind States to implement reductions beyond minimum CAA requirements if needed for attainment does not place the burden of implementing those reductions, in the first instance, on the downwind States. This requirement should be read to go hand-in-hand with the section 110(a)(2)(D) requirement that upwind States include SIP provisions that prohibit their sources from emitting air pollutants in amounts that ''significantly contribute'' to downwind nonattainment. In today's action, EPA is promulgating criteria for interpreting section 110(a)(2)(D) to take into account downwind attainment needs.

As a practical matter, EPA has reviewed the status of Northeast States' efforts to comply with the requirements of the 1990 CAA Amendments and has found that these States have complied with the vast majority of the SIP submission requirements. Even so, EPA is well aware that some of the States have not made certain required submissions.[29–30] However, EPA sees no basis in section 110(a)(2)(D) to mandate that downwind areas complete their SIP planning and implementation before upwind areas are required to begin that process. Upwind areas have been subject to the requirements of section 110(a)(2)(D)—in some form—since the predecessor to this provision was added in the 1977 CAA Amendments. The EPA has determined, through air quality modeling, that even after the downwind States fulfill their prescribed CAA requirements, they will have areas expected to remain in nonattainment. Under these circumstances, the downwind areas continue to constitute areas with air quality in ''nonattainment'' under section 110(a)(2)(D). As a result, upwind areas with emissions in amounts that ''significantly contribute'' to the nonattainment air quality downwind are subject to control requirements whether or not the downwind areas they affect have met all of their planning obligations.

k. Section 110(a)(2)(D) Caselaw. In the NPR, EPA noted that prior to the CAA Amendments of 1990, EPA had issued several rulemakings under section 110(a)(2)(E), the predecessor to section 110(a)(2)(D), and section 126 that addressed the issue of significant contribution in the context of pollutant transport. In those rulemakings, EPA generally applied a multi-factor test to determine whether the emissions from the sources in question constituted a signficant contribution to downwind jurisdictions. In each instance, EPA concluded that the emissions at issue from the upwind sources were not demonstrated to impact downwind air quality in a manner that would constitute significant contribution. Several of these determinations resulted in judicial challenges, but in each instance the courts upheld the Agency's determination of no significant contribution. The EPA indicated in the NPR that the prior rulemakings and the related court holdings, provide limited precedents for today's action. The EPA noted that these decisions have limited relevance because they involved different facts and circumstances, including different pollutants, different

[28] Reductions specifically required by the CAA include, for example, the 3 percent-per-year ROP reductions required of ozone nonattainment areas classified as serious or higher, under section 182(c)(2)(B).

[29–30] If downwind areas fail to meet their planning obligations, they are subject to sanctions (See Section VI, below. As EPA noted in the NPR, 62 FR 60322–23, in some instances, States in the Northeast failed to submit all of their required SIP revisions or other commitments under Phase 1 of the March 2, 1995 Memorandum and as a result, EPA initiated the sanctions process by starting sanctions clocks. In general, those States have since made the required Phase 1 submissions, and EPA terminated the sanctions process by stopping the clocks.

upwind sources, and different downwind effects.

Several commenters asserted that these prior rulemakings and cases are relevant to today's action, and compel EPA to conclude that the emissions from the upwind States affected by today's action do not contribute significantly to downwind nonattainment or maintenance problems. The EPA disagrees that these earlier determinations are controlling and that these earlier determinations are inconsistent with today's action. The EPA responds to these comments in detail in the Response to Comment document.

B. Alternative Interpretation of Section 110(a)(2)(D)

As discussed above, in the NPR EPA advanced an alternative interpretation of section 110(a)(2)(D) (62 FR 60327). Under this alternative interpretation, EPA would determine the level of emissions that significantly contribute to nonattainment downwind based on factors relating to the entire amount of upwind emissions from a particular upwind State and their ambient impact downwind. The EPA would then determine what emissions reductions must be required to adequately mitigate that significant contribution based on factors relating to cost effectiveness of reductions and attainment needs downwind.

The EPA continues to believe that this alternative interpretation remains a permissible interpretation of the statute for the reasons described in the NPR (62 FR 60327). In any event, it should be noted that for purposes of today's action, EPA finds no practical difference between the requirements that would result from the interpretation of section 110(a)(2)(D) adopted today and those that would result from the alternative interpretation described in the NPR. That is, even under the alternative interpretation, today's rulemaking would contain the same findings and require the same SIP revisions as under the interpretation adopted today (62 FR 60327).

C. Weight-of-Evidence Determination of Covered States

As discussed above, EPA applied a multi-factor approach to identify the amounts of NO_X emissions that contribute significantly to nonattainment. The EPA evaluated three air quality factors for each upwind jurisdiction (hereafter referred to as ''States'' or ''upwind States'') to determine whether each has emissions whose contributions to downwind nonattainment problems are large and/or frequent enough to be of concern. Further, for those States whose emissions are large and/or frequent enough to be of concern, EPA applied highly cost-effective controls to determine the amount of NO_x in upwind States which significantly contributes to nonattainment in, or interferes with maintenance by, a downwind State. The EPA also generally reviewed several other considerations before drawing final conclusions. Even though the actual finding of significant contribution applies only to the portion of a State's emissions for which EPA has identified highly cost-effective controls, for ease of discussion, the term ''significant'' (or like term) is used in the discussion in this section to characterize the emissions of each upwind State that make a large and/or frequent contribution to nonattainment in downwind States sufficient to warrant eliminating a portion of its emissions equivalent to what can be removed through those controls.

The purpose of this section is to describe the technical analyses performed by EPA to (a) quantify the air quality contributions from emissions in each upwind State on both 1-hour and 8-hour nonattainment, as well as 8-hour maintenance, in each downwind State, and (b) determine whether these contributions are significant.

In the proposed weight-of-evidence approach, EPA specifically applied several factors to each upwind State, as discussed in Section II.A.3.c, Definition of Significant Contribution. These factors include:

- The overall nature of ozone problem (i.e., ''collective contribution'');
- The extent of the downwind nonattainment problems to which the upwind State's emissions are linked, including the ambient impact of controls required under the CAA or otherwise implemented in the downwind areas; and
- The ambient impact of the emissions from the upwind State's sources on the downwind nonattainment problems.

As part of the analysis of these factors, EPA considered the findings from OTAG's technical analyses, as well as the findings from a number of other studies performed by OTAG participants independent of OTAG. The major findings from these analyses are described below. This is followed by an overview of the approach used by EPA in the proposal for considering the above factors to identify States that make a significant contribution to downwind nonattainment. The comments and EPA's response to comments on EPA's weight-of-evidence proposal are then discussed. Following that discussion, the results of additional State-by-State UAM–V modeling and State-by-State CAM_X [31] source apportionment modeling performed by EPA in response to comments are summarized.[32] The EPA's analysis of the modeling results in terms of the significance of the contributions of upwind States to downwind nonattainment is presented in Section II.C.4, Confirmation of States Making a Significant Contribution to Downwind Nonattainment.

1. Major Findings From OTAG-Related Technical Analyses

The major findings from the air quality and modeling analyses by OTAG and individual OTAG participants that are most relevant to today's rulemaking are as follows:

- several different scales of transport (i.e., intercity, intrastate, interstate, and inter-regional) are important to the formation of high ozone in many areas of the East;
- emissions reductions in a given multistate region/subregion have the most effect on ozone in that same region/subregion;
- emissions reductions in a given multistate region/subregion also affect ozone in downwind multistate regions/subregions;
- downwind ozone benefits decrease with distance from the source region/subregion (i.e., farther away, less effect);
- downwind ozone benefits increase as the size of the upwind area being controlled increases, indicating that there is a cumulative benefit to extending controls over a larger area;
- downwind ozone benefits increase as upwind emissions reductions increase (the larger the upwind reduction, the greater the downwind benefits);
- a regional strategy focusing on NO_X reductions across a broad portion of the region will help mitigate the ozone problem in many areas of the East;
- both elevated and low-level NO_X reductions decrease ozone concentrations regionwide;
- there are ozone benefits across the range of controls considered by OTAG; the greatest benefits occur with the most emissions reductions; there was no ''bright line'' beyond which the benefits of emissions reductions diminish significantly;
- even with the large ozone reductions that would occur if the most

[31] Comprehensive Air Quality Model with Extensions.

[32] The UAM–V and CAM_X models are described in the Air Quality Modeling TSD.

stringent controls considered by OTAG were implemented, there may still remain high concentrations in some portions of the OTAG region; and a regional NO_X emissions reduction strategy coupled with local NO_X and/or VOC reductions may be needed to enable attainment and maintenance of the NAAQS in this region.

The above findings provide technical evidence that transport within portions of the OTAG region results in large contributions from upwind States to ozone in downwind areas, and that a regionwide approach to reduce NO_X emissions is an effective way to address these interstate contributions.

2. Summary of Notice of Proposed Rulemaking Weight-of-Evidence Approach

The EPA relied on OTAG data to develop the information necessary to evaluate the weight-of-evidence factors identified above. These data include emissions (tons) and emission density (tons per square mile), air quality analyses, trajectory, wind vector, and ''ozone cloud'' analyses, and subregional zero-out modeling. In brief, EPA's proposed approach was as follows:

- the OTAG transport distance scale was applied to identify, based on the meteorological potential for transport, which States may contribute to ozone in downwind States;
- the results of the OTAG subregional modeling runs (described below) were used to quantify the extent to which each subregion contributes to downwind nonattainment for the 1-hour and/or 8-hour NAAQS;
- the OTAG 2007 Base Case NO_X emissions and emissions density were used to identify States which emit large amounts of NO_X and/or have a high density of NO_X emissions compared to other States in the OTAG region and, therefore, have NO_X emissions which may be great enough to contribute to downwind nonattainment; and the OTAG 2007 Base Case NO_X emissions were also used to translate the findings from the subregional modeling to a State-by-State basis.

a. Quantification of Contributions. As part of OTAG's assessment of transport, a series of model runs were performed to examine the impacts of emissions from each of 12 multistate subregions on ozone in downwind areas. The locations of these subregions are shown in Figure II–1.

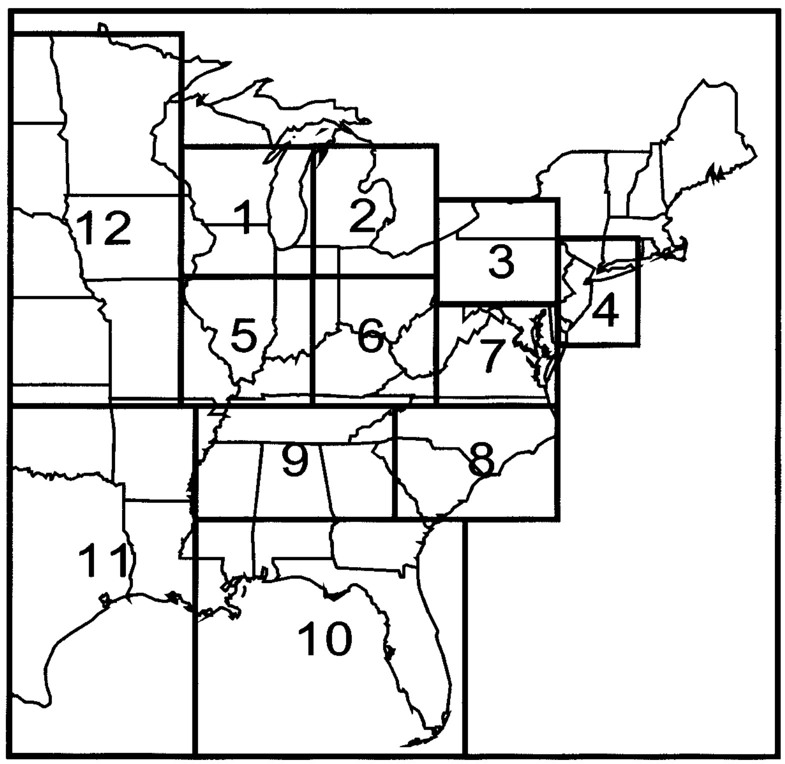

Figure II-1. OTAG Subregions

In each subregional model run, all manmade emissions were removed from one upwind subregion and the model was run for the OTAG July 1988 and 1995 episodes. The ''parts per billion (ppb)'' differences in ozone between each subregional zero-out run compared to the corresponding 2007 Base Case run were used to quantify the air quality impacts of the subregion on nonattainment downwind.

In the proposed NO_X SIP call, EPA considered areas as ''nonattainment'' if air quality monitoring indicates that the area is currently measuring nonattainment and if air quality modeling indicates future nonattainment, taking into account CAA control requirements and growth. In this regard, areas were considered nonattainment for the 1-hour NAAQS if they had 1994–1996[33] monitoring data indicating measured 1-hour violations and 2007 Base Case 1-hour predictions >=125 ppb. Areas were considered to be nonattainment for the 8-hour NAAQS if they had 1994–1996 monitoring data indicating measured 8-hour violations and 2007 Base Case 8-hour predictions >=85 ppb. The inconsistency between the form of the 8-hour NAAQS, which considers 3 years of data for determining the average of the fourth-highest 8-hour daily maximum concentration at a monitor, and the limited predictions available from the OTAG episodes introduced a complication to the analysis of 8-hour contributions. It was not possible to use the model predictions in a way that explicitly matched the form of the 8-hour NAAQS. Instead, an analysis of seasonal and episodic ozone measurements was performed in an attempt to link 8-hour measured concentrations during the OTAG episodes to the form of the 8-hour NAAQS, as closely as possible. The results of that analysis indicated that the 3-episode average of the second highest 8-hour ozone concentrations measured during the OTAG 1991, 1993, and 1995 episodes corresponded best, overall, to the 3-year average of the fourth highest 8-hour daily ambient data. However, since OTAG subregional modeling was only available for the 1988 and 1995 episodes, EPA used the concentrations during these two episodes in calculating average second high 8-hour concentrations.[34]

b. Evaluation of 1-Hour and 8-Hour Contributions. In the proposal, EPA summarized the ''ppb'' contributions to downwind nonattainment from each subregion in terms of both the frequency and the magnitude of the downwind impacts over specific concentration ranges (e.g., 2 to 5 ppb, 5 to 10 ppb, 10 to 15 ppb, etc.). The results indicate that, in general, large contributions to downwind nonattainment occur on numerous occasions. Although the level of downwind contribution varies from subregion to subregion, a consistent pattern is apparent for both 1-hour nonattainment and 8-hour nonattainment. Specifically, the results of the subregional modeling indicate that emissions from States in subregions 1 through 9 produce large 1-hour and 8-hour contributions downwind in terms of the magnitude and frequency, including geographic extent, of the downwind impacts. In addition, nonattainment areas within many States in the OTAG region receive large and/or frequent contributions from emissions in these subregions. The EPA proposed to find that most of the States whose emissions are wholly or partially contained within one or more of these subregions (i.e., Alabama, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Maryland, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin, as well as the District of Columbia) are making a significant contribution to downwind nonattainment. In addition to the ambient impact demonstrated by the subregional modeling, this proposed finding was based on a determination that:

- OTAG strategy modeling and non-OTAG modeling indicate that NO_X emissions reductions across these States would produce large reductions in 1-hour and 8-hour ozone concentrations across broad portions of the region including 1-hour and 8-hour nonattainment areas;
- these States are upwind from nonattainment areas within the 1- to 2-day distance scale of transport;
- these States form a contiguous area of manmade emissions covering most of the core portion of the OTAG region;
- 11 of the States that are wholly within subregions 1 through 9 have a relatively high level of NO_X emissions from sources in their States; these States are ranked in the top 50 percent of all States in the region in terms of total NO_X emissions and/or have NO_X emissions exceeding 1000 tons per day;
- States wholly within subregions 1 through 9 with lesser emissions have a relatively high density of NO_X emissions;
- for the seven States that are only partially contained in one of subregions 1 through 9, the State total NO_X emissions, as well as each State's contribution to NO_X emissions in the subregions in which they are located, indicate that six of the States each have: NO_X emissions that are more than 10 percent of the total NO_X emissions in one of these subregions, NO_X emissions in the top 50 percent among all States, and/or a majority of its NO_X emissions within one of these subregions.

For the New England States that were not included in any of the OTAG zero-out subregions, EPA found that two of these States (i.e., Massachusetts and Rhode Island) have a high density of NO_X emissions. Also, the trajectory and wind vector analyses indicated that these States are immediately upwind of nonattainment areas in other States.

For the nine States in the OTAG region which are wholly within subregions 10, 11, and 12 (i.e., Florida, Kansas, Louisiana, Minnesota, Nebraska, North Dakota, Oklahoma, South Dakota, and Texas), and for Arkansas, Iowa, and Mississippi, EPA proposed that emissions from each of these States should be considered not to significantly contribute to downwind nonattainment. These States are further discussed below in Section II.C.5, States Not Covered by this Rulemaking.

c. Comments and Responses on Proposed Weight-of-Evidence Approach to Significant Contribution. The EPA received a number of comments on various elements of the proposed weight-of-evidence approach. In addition, EPA received new modeling and analyses performed by commenters which address the issue of significant contribution. The following is a summary of the major comments received by EPA and the responses to these comments. Additional comments and EPA's response to these comments are provided in the Response to Comment document.

Comment: Some commenters stated that it was inappropriate to use a weight-of-evidence approach to determine the significance of upwind emissions on downwind nonattainment. Rather, it was argued that EPA should use a specific ''bright line'' criterion. Other commenters supported the weight-of-evidence approach.

Response: The magnitude and frequency of contributions from an upwind State to downwind nonattainment depend on the extent of the nonattainment problem in the downwind area, the emissions in the downwind area, the emissions in the upwind State, the distance between the upwind State and the downwind area, and weather conditions (i.e., winds and temperatures which favor ozone formation and transport). Because these factors vary in a complex way across the OTAG region, it is not possible to develop a single bright line test for significance that will be applicable and appropriate for all potential upwind-State-to-downwind-area linkages. Therefore, EPA believes that it is more appropriate to use a weight-of-evidence approach to account for all of these factors than establishing a bright line criterion.

Comment: Some commented that EPA should not use the trajectory, wind vector, and ''ozone cloud'' analyses as a

[33] Data for 1994–1996 were used because these were the most recent quality-assured data available at the time the analysis was performed.

[34] In response to comments, EPA has reexamined the method for relating 8-hour model predictions during the OTAG episodes to the form of the 8-hour NAAQS. This is discussed further in Section II.C.2.c, Comments and Responses on the Proposed Weight of Evidence Approach to Significant Contribution.

basis for determining significant contribution because these techniques indicate air movement and do not account for ozone formation and depletion due to photochemical reactions and other processes. Other commenters argued in favor of using this information as means of linking upwind States with downwind nonattainment.

Response: The EPA agrees that information from such techniques should not be used as the sole basis for finding that certain upwind States significantly contribute to nonattainment in specific downwind States. However, EPA believes that it is important to consider the ''movement'' of ozone and/or precursors as part of the air quality evaluation of contributions from upwind States. This factor is incorporated into the air quality models used by EPA for this rulemaking. The inclusion of this information, in conjunction with numerous other air quality factors in the models, provides for a more technically robust analysis than can be provided by the trajectory, ozone cloud, and wind vector analyses alone.

Comment: A number of commenters stated that CAA section 110(a)(2)(D) requires a State-by-State demonstration that emissions within an upwind State make a significant contribution to nonattainment in another State and thus, EPA's proposed approach of using subregional (i.e., multistate) modeling, together with each upwind State's NO_X emissions, to establish these linkages is legally flawed. These commenters argued that section 110(a)(2)(D) requires ''each implementation plan submitted by a State'' to contain provisions that prohibit any source or other type of emissions activity ''within the State'' from emitting air pollutants in amounts that contribute significantly to a downwind nonattainment problem. The commenters concluded that these provisions require, as a matter of technical procedure, that EPA must base its determination that emissions from a particular State significantly contribute to nonattainment downwind on a technical analysis of that particular State's emissions. According to the commenters, section 110(a)(2)(D) by its terms, prohibits EPA from making that technical determination by examining the impact of emissions from a group of States on a downwind nonattainment problem, and then extrapolating from that information to determine whether emissions from each State within that group should be considered to make a significant contribution.

As a technical matter, these commenters argue that if emissions from more than one State are lumped together in assessing the contribution to a downwind State, there is no way to determine the amount of emissions in each contributing State that must be reduced. The commenters argue that the only way to establish specific upwind State to downwind State linkages is through air quality modeling on a State-by-State basis. Further, the commenters contend that once an area beyond a particular State's boundaries is modeled, there is no way of knowing how much farther upwind to go in terms of defining a source area. In order to address these issues, many commenters stated that EPA must do State-by-State zero-out UAM–V modeling and/or State-by-State source apportionment modeling using the CAMx model to determine downwind contributions from upwind States.

Response: On the legal issue, EPA disagrees that the above-referenced provisions of section 110(a)(2)(D), by their terms, mandate the technical procedure for EPA to make the determination of significant contribution. These provisions simply indicate that EPA must make that determination on a SIP-by-SIP basis, that is, for EPA to issue a SIP call with respect to a particular State, EPA must determine that the provisions of that SIP fail to adequately control emissions from sources within the State. However, these provisions do not mandate any particular technical procedure for making that determination. As a result, EPA may employ any technical procedure that is sufficiently accurate. As discussed below, EPA believes that its subregional approach is sufficiently accurate to justify the SIP call. However, in response to this and other comments, EPA did conduct State-by-State modeling. The results of this modeling, as discussed below, confirm the results of the subregional modeling.

On the technical issue, EPA used the subregional modeling as part of the proposed approach because OTAG had developed and relied on this modeling as part of its analysis to quantify the impacts of manmade emissions in upwind areas on ozone in downwind areas. In addition, in conjunction with other information, EPA believes that it is possible to make rational extrapolations from the subregional results in order to draw conclusions as to the contribution of individual States. The EPA believes that it is credible to use NO_x emissions in each State, along with the subregional modeling results, in the determination of significance in view of the results of OTAG modeling which indicate that, in addition to local emissions, the level of ozone in a downwind State is directly related to the magnitude of NO_x emissions in upwind areas and the proximity of the upwind area to the downwind State. A more detailed discussion of the technical validity of the subregional modeling is contained in the Response to Comment Document.

The EPA recognizes that State-by-State modeling would provide some additional precision to the magnitude and frequency of individual State-to-State contributions. In response to the recommendations for additional modeling, EPA performed both State-by-State UAM–V zero-out modeling and State-by-State CAMx source apportionment modeling for many of the upwind States in the OTAG region which were proposed as significant contributors. The EPA's analysis of the contributions to downwind nonattainment using the State-by-State modeling confirms the overall finding, based on the proposed subregional modeling, that the 23 jurisdictions identified in the proposal significantly contribute to nonattainment in downwind States. Specifically, the subregional modeling indicates that manmade emissions from sources in subregions 1 through 9 make large and/or frequent contributions to 1-hour and 8-hour nonattainment in specific downwind States. The EPA's analysis of the State-by-State modeling demonstrates that each of the 23 upwind jurisdictions identified through subregional modeling significantly contribute to nonattainment in specific downwind States. In addition, the results of the State-by-State modeling show that the specific upwind-State-to-downwind-nonattainment linkages indicated by the subregional modeling are confirmed overall by the State-by-State modeling. The State-by-State modeling analyses are summarized below and more fully documented in the Air Quality Modeling TSD.

Comment: The EPA received comments that zero-out modeling introduces sharp spatial changes in emissions and pollutants along the edges of the zero-out area. The commenters contend that this is not credible and provides an incorrect assessment of transport.

Response: The EPA disagrees with this comment, as discussed in the Response to Comments document. Also, as indicated above, in response to other comments, EPA has performed CAMx source apportionment modeling which does not use a zero-out technique for quantifying ozone contributions from upwind States. In general, EPA has found that the source apportionment technique and zero-out modeling provide consistent information on the relative contribution of upwind States to downwind nonattainment. In cases where the two techniques do not provide consistent results, the source apportionment technique tends to indicate larger contributions than the zero-out modeling. The differences between these two modeling techniques are described further in the Air Quality Modeling TSD.

Comment: Some comments referenced a study which analyzed the ''noise'' (i.e., uncertainty) in the UAM–V modeling system. This study purports to show that the contributions from some States EPA proposed as significant are within the ''noise'' of the model.

Response: This study focuses on model uncertainty by varying many, but not all, inputs to the model. The study does not contend that the inputs selected by OTAG are incorrect, but rather that there may be other plausible values for these inputs. The results indicate that there is a range of uncertainty in predicted ozone associated with the range of possible values for the particular inputs studied by the commenter. The study does not indicate that there is any bias in the model's predictions (i.e., there is no indication that the predictions are too high or too low). The specific values for the inputs being used by EPA in its air quality modeling are the same values that were used by OTAG. These values were selected by the OTAG Regional and Urban Scale Modeling Work Group, which included experts in air quality modeling from the public and private sector, in conjunction with the model's developers, Systems Application International. The predictions from OTAG's model runs using these same input values were evaluated against ambient measurements and found by OTAG to provide acceptable results. The EPA continues to believe that the specific inputs selected by OTAG are technically sound and the modeling results are credible. A further discussion of EPA's response to this comment is in the Response to Comments document.

Comment: Several commenters stated that emissions from large point sources of NO_x in specific States do not contribute significantly to downwind nonattainment.

Response: As discussed in Section II.A.3.c, Definition of Significant Contribution, under EPA's collective contribution approach, if emissions in the aggregate from a particular geographic region or State are found to contribute significantly to nonattainment downwind, then the emissions in that region or State are considered to be significant contributors to that nonattainment problem. Moreover, EPA treats emissions as ''contributing significantly'' only to the extent they may be eliminated through highly cost-effective reductions. Thus, if all emissions from a State, when considered in the aggregate, are found to contribute significantly to nonattainment downwind, and if there are highly cost-effective controls for NO_x emissions from sources in the upwind State, then the amount of NO_x emissions from these sources that can be eliminated with such controls are considered to be making a significant contribution. The amount of emissions determined through this approach to make a significant contribution may be relatively small, compared to the upwind State's entire inventory; and the ambient impact downwind of eliminating that amount may be relatively small as well. However, this small impact does not mean that the emissions themselves are not significant insofar as their contribution to nonattainment downwind. Further, as discussed in Section IV, Air Quality Assessment, when the amount of emissions required to be eliminated from upwind States are combined and modeled collectively, their ambient impact downwind is larger.

Comment: One commenter provided a recommendation for dealing with the concern that the spatial resolution of meteorological inputs to the air quality model may be too coarse to require that predicted exceedences correspond exactly with a county violating the NAAQS. The commenter's recommendations were to base the selection of 1-hour nonattainment receptors on model predicted exceedences in either (a) all counties within the metropolitan statistical area containing the nonattainment area or (b) all counties comprising the designated 1-hour nonattainment area.

Response: The EPA believes that the appropriate way to address this issue is to use all counties comprising the designated 1-hour nonattainment area. That is, all counties in a designated 1-hour nonattainment area should be considered as possible nonattainment receptors for the purposes of evaluating contributions to nonattainment under the 1-hour NAAQS. The EPA recognizes that not all counties within a designated nonattainment area have monitors, and that some counties may have monitors that indicate attainment in that county. Even so, EPA recognizes that under the 1-hour NAAQS, nonattainment boundaries are generally used to describe an area with the nonattainment problem. Thus, EPA believes that this geographic vicinity offers the best indication of an area that may be expected to have nonattainment air quality somewhere within its boundaries. The EPA believes that it is appropriate to include all counties in the designated nonattainment area because the entire nonattainment area is responsible for meeting the 1-hour NAAQS, even if only one monitor measures nonattainment at any one time. As noted elsewhere, EPA predicts that many 1-hour nonattainment areas that currently monitor nonattainment somewhere within the area will remain in nonattainment in 2007, in some cases because of predicted violations in counties that currently monitor attainment. The EPA believes that the entire area should be considered to be in nonattainment until all monitors in the area indicate attainment of the NAAQS. Thus, in today's rulemaking, EPA used the designated 1-hour nonattainment area in selecting the receptors to be used to evaluate impacts on downwind nonattainment problems.

Comment: Several commenters questioned the validity of EPA's approach of using the 3-episode average of the second highest 8-hour daily maximum concentration to represent the form of the 8-hour NAAQS (i.e., the 3-year average of the fourth highest 8-hour daily maximum values at a monitor[35]). Commenters expressed the concern that the average second high may not be representative for all areas across the OTAG domain. However, none of the commenters provided any suggested alternatives to EPA's approach.

Response: The analysis performed by EPA to establish a relationship between the air quality during the OTAG episodes and the form of the 8-hour NAAQS was based upon an analysis of 3 years of monitoring data compared to monitoring data during the OTAG episodes. In response to comments, EPA performed an analysis to determine how the predicted average second high 8-hour values, as well as several alternative 8-hour values, compared to ambient 8-hour design values, based on 1994 to 1996 measured data. Based on this analysis, EPA determined that, overall, the model-predicted average second high values underestimate the corresponding ambient design values for those counties in the OTAG domain with 1994–1996 ambient values >=85 ppb. In addition to the average second high, EPA also compared six other measures of 8-hour model predictions to ambient design values. The six other measures include the highest, second

[35] For the purposes of discussion in this Section, these values are referred to as ''design'' values.

highest, third highest, and fourth highest ozone predictions across the July 1991, 1993, and 1995 episodes; the 3-episode average of the highest concentrations; and the 3-episode average of the highest, second highest, and third highest concentrations. The EPA also developed the same measures using model predictions from all 4 episodes for comparison to the ambient design values. The results indicate that none of the alternative measures provides a universal best match to ambient 8-hour design values in all States. Each of the indicators overestimates values in some areas and underestimates values in other areas to a varying extent. Furthermore, the best representation of 8-hour design values using predictions from the OTAG episodes varies from State to State. Given that the predicted average second high underestimates ambient 8-hour design values and that none of the other 8-hour indicators examined by EPA provides a ''best'' match to ambient values in all cases, EPA has decided to analyze the contributions to 8-hour nonattainment problems using all 8-hour predictions >=85 ppb. The EPA believes that this approach is appropriate given that EPA is using modeling results for the 8-hour NAAQS merely as an indicator of the likelihood that areas that currently monitor violations of the 8-hour NAAQS will continue to be nonattainment for the 8-hour NAAQS and/or have 8-hour maintenance problems in 2007.[36] Thus, the air quality analysis of 8-hour contributions, described below, focuses on all 8-hour values >=85 ppb.

Comment: Several commenters submitted new State-by-State zero-out modeling using UAM–V and CAM_x source apportionment modeling purporting to show that contributions from particular upwind States are insignificant.

Response: The EPA reviewed the commenters' modeling to determine and assess (a) the technical aspects of the models that were applied; (b) the types of episodes modeled; (c) the methods for aggregating, analyzing, and presenting the results; (d) the completeness and applicability of the information provided; and (e) whether the technical evidence supports the arguments made by the commenters. Overall, the modeling submitted by commenters is viewed by EPA as generally technically credible, although not complete in all cases. The EPA's ability to fully evaluate and utilize the modeling submitted by commenters was hampered in some cases because only limited information on the results was provided. For example, a commenter may have provided results for only 1 or 2 days in an episode, or for only one of several episodes with no information presented on the results for the remaining days or episodes that were modeled. As another example, results were presented for only the peak ozone day in an episode while greater contributions may have been predicted on other high ozone days of the episode. For some of the modeling, the information was only presented in graphical form which made the results difficult to evaluate in a quantitative way. Also, in some cases the model predictions were only presented as episode composite values without information on peak contributions. The EPA's full assessment of the modeling submitted by commenters is provided in the Response to Comments document.

In light of the absence of complete information in the modeling provided by commenters and other comments calling for State-by-State analyses, EPA decided to perform additional air quality modeling of the type submitted by commenters in order to consider all of the data resulting from such model runs. The EPA modeling includes State-by-State zero-out modeling using UAM–V and State-by-State CAM_x source apportionment modeling.

EPA conducted further analysis of other factors included in the multi-factor approach for significant contribution. The results of EPA's consideration of these factors and EPA's modeling are described next.

3. Analysis of State-specific Air Quality Factors

a. Overall Nature of Ozone Problem (''Collective Contribution''). As described above, EPA believes that each ozone nonattainment problem at issue in today's rulemaking is the result of emissions from numerous sources over a broad geographic area. The contribution from sources in an upwind State must be evaluated in this context. This ''collective contribution'' nature of the ozone problem supports the proposition that the solution to the problem lies in a range of controls covering sources in a broad area, including upwind sources that cause a substantial portion of the ozone problem. This upwind share is typically caused by NOx emissions from sources in numerous States. States adjacent to the State with the nonattainment problem generally make the largest contribution, but States further upwind, collectively, make a contribution that constitutes a large percentage in the context of the overall problem. As an example to illustrate the overall nature of the ozone problem, EPA discusses below the ozone problem in the New York City nonattainment area.

b. Extent of Downwind Nonattainment Problems. For each downwind area to which an upwind State may be linked, EPA also examined the extent of the downwind nonattainment problem, including the air quality impacts of controls required in downwind areas under the CAA, as well as of controls required or implemented on a national basis. As indicated elsewhere, EPA determined that a downwind area should be considered ''nonattainment'' for purposes of section 110(a)(2)(D)(i)(I) under the 1-hour NAAQS if the area currently (as of the 1994–96 time period) has nonattainment air quality[37] and if the area is modeled to have nonattainment air quality in the year 2007, after implementation of all measures specifically required of the area under the CAA as well as implementation of Federal measures required or expected to be implemented by that date. The EPA determined that each such downwind area had a residual nonattainment problem even after implementation of all these control measures. The presence of residual nonattainment is a factor that supports the need to reduce emissions from upwind sources to allow further progress towards attainment.[38] As an example, the residual nonattainment for the New York City area is discussed in more detail below.

[36] Similarly, the EPA is also using 1-hour model predictions >=125 ppb as an indicator that areas currently designated nonattainment for the 1-hour NAAQS will continue to be nonattainment for the 1-hour NAAQS in 2007.

[37] As explained elsewhere, for the 1-hour standard, EPA based its determination as to the boundaries of the area with air quality violating the NAAQS on the boundaries of the area designated as nonattainment.

[38] Indeed, the modeling relied on in today's action indicates that many downwind nonattainment areas carry a residual nonattainment problem even after implementation of regional reductions by all the States affected by today's action. Although not essential to EPA's conclusions, the presence of this nonattainment problem even after implementation of regional controls, based on the modeling used in today's rulemaking, indicates that even further reductions, regionally or locally, would be needed to assure attainment in those downwind areas.

c. Air Quality Impacts of Upwind Emissions on Downwind Nonattainment. As indicated above, in response to comments, additional air quality modeling was performed by EPA to confirm the proposed approach which relied on subregional modeling to quantify the impacts of emissions from upwind States on nonattainment in downwind areas. The additional modeling consisted of State-by-State zero-out modeling using UAM–V and State-by-State source apportionment modeling using the CAMx Anthropogenic Precursor Culpability Assessment (APCA) technique.[39] A description of these models is contained in the Air Quality Modeling TSD. Both models are currently being used by the scientific and regulatory community for air quality assessments. The EPA is not aware of any information that would indicate that either model provides more credible predictions than the other. Each modeling technique (i.e., zero-out and source apportionment) provides a different technical approach to quantifying the downwind impact of emissions in upwind States. The zero-out modeling analysis provides an estimate of downwind impacts by comparing the model predictions from a Base Case run to the predictions from a run in which the Base Case manmade emissions are removed from a specific State. In contrast, the source apportionment modeling quantifies downwind impacts by tracking formation, chemical transformation, depletion, and transport of ozone formed from emissions in an upwind source area and the impacts that ozone has on nonattainment in downwind areas. The EPA ran both models for all four OTAG episodes (i.e., July 1–11, 1988; July 13–21, 1991; July 20–30, 1993; and July 7–18, 1995) using the 2007 SIP Call Base Case emissions. The development of emissions for this Base Case scenario are described in Section IV, Air Quality Assessment.

The EPA selected several metrics in order to evaluate the downwind contributions from emissions in upwind States. The metrics were designed to provide information on the three fundamental factors for evaluating whether emissions in an upwind State make large and/or frequent contributions to downwind nonattainment. These factors are (a) the magnitude of the contribution, (b) the frequency of the contribution, and (c) the relative amount of the contribution. The magnitude of contribution factor refers to the actual amount of ''ppbs'' of ozone contributed by emissions in the upwind State to nonattainment in the downwind area. The frequency of the contribution refers to how often the contributions occur and how extensive the contributions are in terms of the number of grids in the downwind area that are affected by emissions in the upwind State. The relative amount of the contribution is used to compare the total ''ppb'' contributed by the upwind State to the total ''ppb'' of nonattainment in the downwind area.

As indicated above, two modeling techniques (i.e., UAM–V zero-out and CAMx source apportionment) were used for the State-by-State evaluation of contributions. The EPA developed metrics for both modeling techniques for each of the three factors. However, because of the differences between the two techniques, some of the metrics used for the UAM–V modeling and the CAMx modeling are different. The specific UAM–V and CAMx metrics and how they relate to the three factors used for the evaluation of contributions are described below.

The EPA examined the contributions from upwind States to downwind nonattainment for several types of nonattainment receptors. Nonattainment receptors for the 1-hour analysis include those grid cells that (a) are associated with counties designated as nonattainment for the 1-hour NAAQS and (b) have 1-hour Base Case model predictions >=125 ppb. These grid cells are referred to as ''designated plus modeled'' nonattainment receptors. Using these receptors, the metrics were calculated for each 1-hour nonattainment area as well as for each State. To calculate the metrics by State, all of the 1-hour nonattainment receptors in that State were pooled together.[40] Table II–1 lists the 1-hour nonattainment areas that were considered in this analysis, along with the State(s) in which the nonattainment area is located. In addition to the areas listed in Table II–1, EPA also evaluated the contributions of upwind States to ozone concentrations over Lake Michigan because modeled air quality over the lake can be indicative, under certain weather conditions, of air quality in portions of the States surrounding the lake.[41]

TABLE II–1.—1-HOUR NONATTAINMENT AREAS EVALUATED

Nonattainment area	State(s)
Atlanta	Georgia.
Baltimore	Maryland.
Birmingham	Alabama.
Boston/Portsmouth [1]	Massachusetts, New Hampshire.
Chicago/Milwaukee [2]	Illinois, Indiana, Wisconsin.
Cincinnati	Kentucky, Ohio.
Greater Connecticut	Connecticut.
Louisville	Indiana, Kentucky.
Memphis	Mississippi, Tennessee.
New York City	Connecticut, New Jersey, New York.
Philadelphia	Delaware, Maryland, New Jersey, Pennsylvania.
Pittsburgh	Pennsylvania.
Portland	Maine.
Rhode Island	Rhode Island.
Southwestern Michigan [3]	Michigan.

[39] For ease of discussion, EPA is using the term ''UAM–V'' to refer to the UAM–V State-by-State zero-out modeling and the term ''CAMx'' to refer to the CAMx source apportionment modeling.

[40] For ease of discussion in this Section, the 1-hour nonattainment areas and the set of nonattainment receptors pooled over an entire State are referred to as downwind areas.

[41] High measured ozone concentrations in portions of Illinois, Indiana, Michigan, and Wisconsin near the shoreline of Lake Michigan are often associated with weather conditions which cause ozone precursor pollutants to be blown offshore over the lake during the morning, where they can form high ozone concentrations which then return onshore during ''lake breeze'' wind flows in the afternoon. Because the size of the grid cells used in the OTAG modeling is relatively large compared to the spatial scale of the lake breeze, the high ozone concentrations predicted over the lake may not be blown back onshore in the model. Since high concentrations over the lake do, in reality, impact air quality along the shoreline of one or more of these States, the EPA believes that it is appropriate to use predicted contributions to ozone over Lake Michigan as a surrogate for contributions to any one of the surrounding States (i.e., Illinois, Indiana, Michigan, and Wisconsin).

TABLE II–1.—1-HOUR NONATTAINMENT AREAS EVALUATED—Continued

Nonattainment area	State(s)
St. Louis	Illinois, Missouri.
Washington, DC	District of Columbia, Maryland, Virginia.
Western Massachusetts	Massachusetts.

[1] For the purposes of this analysis EPA has combined the Greater Boston nonattainment area which includes portions of Massachusetts and New Hampshire, with the Portsmouth, New Hampshire nonattainment area into a single downwind nonattainment receptor area.
[2] For the purposes of this analysis EPA has combined the 1-hour nonattainment counties that are along the shoreline of Lake Michigan in the States of Illinois, Indiana, and Wisconsin into a single downwind nonattainment receptor area.
[3] For the purposes of this analysis EPA has combined the 1-hour nonattainment counties that are along the shoreline of Lake Michigan in the State of Michigan into a single downwind nonattainment receptor area.

For the 8-hour analysis, nonattainment receptors are those grid cells that (a) are associated with counties currently violating the 8-hour NAAQS (based on 1994–1996 data) and (b) have 8-hour Base Case model predictions >=85 ppb. These grid cells are referred to as ''violating plus modeled'' nonattainment receptors. The metrics for the 8-hour contribution analyses were calculated on a State-by-State basis by pooling together the ''violating plus modeled'' receptors in a State.

(1) UAM–V State-by-State Modeling. In the UAM–V zero-out model runs all manmade emissions in a given upwind State were removed from the Base Case scenario. Each zero-out scenario was run for all 4 episodes and the ozone predictions in downwind States were then compared to those from the Base Case run in order to quantify the downwind impacts of emissions from the upwind State (i.e., the State in which the manmade emissions were removed). The EPA performed zero-out runs for the following set of States:

• Alabama, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Michigan, Missouri, North Carolina, Ohio, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

Zero-out modeling for Massachusetts was performed because this State was the only State in the Northeast with relatively large NO_X emissions that was not included in any of the OTAG subregional modeling. The other States listed above were selected for zero-out modeling in order to respond to comments that emissions in all or portions of each of these States do not contribute significantly to downwind nonattainment.

The EPA analyzed the model-predicted ozone concentrations from the zero-out runs using the four metrics described below. The results for these metrics are too voluminous to include in the notice in their entirety. The full set of results is contained in the Air Quality Modeling TSD. Each metric was calculated using 1-hour daily maximum concentrations >=125 ppb as well as 8-hour daily maximum concentrations >=85 ppb. Model predictions from all 4 episodes were used for calculating the metrics.[42]

UAM–V Metric 1: Exceedences. This metric is the total number of predicted concentrations exceeding the NAAQS (i.e. 1-hour values >=125 ppb and 8-hour values >=85 ppb) within the downwind area. In calculating this metric, EPA summed the number of occurrences of values above the applicable standard (i.e., 1-hour or 8-hour) for all nonattainment receptors within the downwind area. For example, in Downwind Area #1 there are five 1-hour ''designated plus modeled'' nonattainment receptors. For this downwind area, the Base Case value for Metric 1 is calculated by first counting the number of days, across all four episodes, that had 1-hour daily maximum values >=125 ppb at each of the five receptors. The result is the total number of exceedences at each receptor over all days in all four episodes. The total number of exceedences at each receptor is then summed across all five receptors to produce the total number of exceedences in Downwind Area #1, which is the value for Metric 1 for this area.

UAM–V Metric 2: Ozone Reduced—ppb. This metric shows the magnitude and frequency of the ''ppb'' impacts from each upwind State on ozone concentrations in each downwind area. These impacts are quantified by calculating the difference in ozone concentrations between the zero-out run and the Base Case. The results are then tabulated in terms of the number of ''impacts'' within six concentration ranges: >=2 to 5 ppb, >=5 to 10, >=10 to 15, >=15 to 20, >=20 to 25, and >=25 ppb. The impacts for 1-hour daily maximum values and 8-hour daily maximum values are determined by tallying the total ''number of days and grid cells'' >=125 ppb or >=85 ppb that receive contributions within the concentration ranges. In the analysis of contributions, as described below, the data from Metric 2 are used in conjunction with Metric 1 to determine the percent of the exceedences in the downwind area that receive contributions of >=2 ppb, >= 5 ppb, >=10, ppb, etc. The maximum ''ppb'' impact within the downwind area is also calculated.

UAM–V Metric 3: Total ppb Reduced. This metric quantifies the total ppb contributed in the downwind area from an upwind State, not including that portion of the contribution that occurs below the level of the NAAQS. For 1-hour concentrations, Metric 3 is calculated by taking the difference between the Base Case predictions in each nonattainment receptor and either (a) the corresponding value in the zero-out run, or (b) 125 ppb, whichever is greater (i.e., 125 ppb or the prediction in the zero-out run). The Base Case vs. zero-out differences are summed over all days and across all nonattainment receptors in the downwind area. The calculation of this metric is illustrated by the following example. If the Base Case 1-hour daily maximum ozone prediction is 150 ppb and the corresponding value from the zero-out run is 130 ppb, then the difference used in this metric is 20 ppb. However, if the value from the zero-out run is 115 ppb, then the difference used in this metric is 25 ppb (i.e., 150 ppb–125 ppb, because 115 ppb is less than 125 ppb).

For analyzing the contributions using Metric 3, the values of this metric are compared to the total amount of ozone above the NAAQS (i.e., 125 ppb, 1-hour or 85 ppb, 8-hour) in the Base Case. This baseline measure of the ''total amount of nonattainment'' (i.e., the total ''ppb'' of ozone that is above the NAAQS) is calculated by summing the ''ppb'' values in the Base Case that are above the level of the NAAQS. The total contribution from an upwind State to a particular downwind area calculated by Metric 3 is expressed in relation to the

[42] Model predictions from the first few days of each episode are considered ''ramp-up'' days and were excluded from the analysis, following the procedures adopted by OTAG. The ramp-up days include the first 3 days of the July 1988, 1991, and 1995 episodes and the first 2 days of the July 1993 episode.

amount that the downwind area is in nonattainment. For example, if Upwind State #1 contributes a total of 50 ppb >=125 ppb to Downwind Area #2 and the total Base Case ozone >=125 ppb in Downwind Area #2 is 500 ppb, then the contribution from Upwind State #1 (i.e., 50 ppb) to Downwind Area #2 is equivalent to 10 percent of Downwind Area #2's nonattainment problem (i.e., 50 ppb divided by 500 ppb, times 100).

UAM–V Metric 4: Population-Weighted Total ppb Reduced. This metric is similar to the ''Total ppb Reduced'' metric except that the calculated contributions are weighted by (i.e., multiplied by) population. In calculating this metric, the ''ppb'' contributions are determined for each nonattainment receptor, then summed across all nonattainment receptors in a particular downwind area. During this calculation, the population in the nonattainment receptor is multiplied by the total contribution in that receptor (i.e., grid cell) and then this value is added to the corresponding values for the other receptors in the downwind area. The results for this metric are expressed relative to the population-weighted Base Case amount similar to the approach followed with Metric 3, as described above.

(2) CAMx Source Apportionment Modeling. In the CAMx modeling, the source apportionment technique was used to calculate the contributions from upwind States to ozone concentrations above the NAAQS in downwind areas. Due to computational constraints, it was not possible for EPA to treat each State in the OTAG region as a separate source area. Several of the smaller States in the Northeast were grouped together as were seven States in the far western portion of the region. The following States were treated as individual source areas:

• Alabama, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

The following States were grouped together:

• Connecticut and Rhode Island were combined; Maryland, Delaware and the District of Columbia were combined; New Hampshire and Vermont were combined; and Arkansas was combined with the portions of Oklahoma, Kansas, Minnesota, Nebraska, North Dakota, and South Dakota that lie within the OTAG region.

The contributions from each of these source areas to downwind nonattainment were evaluated using four metrics. As indicated above, the CAMx metrics are calculated for the same types of nonattainment receptors as the UAM–V zero-out metrics. The CAMx metrics are calculated in a way that is different from the metrics used for the zero-out runs in large part because of the differences between the two techniques. The zero-out modeling calculates contributions using the difference in predictions between two model runs (i.e., a Base Case and a State-specific zero-out run). In contrast, the CAMx source apportionment technique calculates contributions by internally tracking ozone formed from emissions in each source area. In raw form, the source apportionment technique produces a ''ppb'' contribution from each source area to hourly ozone in each receptor grid cell. The individual hourly ''ppb'' contributions were treated in the way described below to calculate 1-hour and 8-hour values for the four metrics. The approach was based on recommendations to EPA by Environ, the developers of CAMx. For 1-hour concentrations the metrics are calculated based on contributions to all hourly predictions >=125 ppb. For 8-hour concentrations, the metrics are calculated based on the contribution to every 8-hour period in a day with an average concentration >=85 ppb. In order to provide a link to the way 1-hour and 8-hour concentrations were treated for the zero-out runs, EPA also calculated the CAMx metrics for 1-hour daily maximum values >=125 ppb and 8-hour daily maximum values >=85 ppb.[43] The full set of results for all of the CAMx metrics is contained in the Air Quality Modeling TSD.

The CAMx Metrics 1 and 2 provide information on the magnitude and frequency of contributions in a form that is similar to UAM–V Metrics 1 and 2.

CAMx Metric 3: Highest Daily Average Contribution. This metric is the highest daily average ozone ''ppb'' contribution from each upwind source area to each downwind nonattainment receptor area over all days modeled in all four episodes. The following example illustrates how this metric is calculated for 1-hour ozone concentrations. Similar procedures are followed for calculating this metric for 8-hour concentrations. First, the hourly ''ppb'' contributions from a particular upwind source area to each nonattainment receptor in a downwind area are summed across all receptors in the downwind area. This total daily contribution is then divided by the number of hours and grid cells >=125 ppb in the downwind area to determine the daily average ''ppb'' contribution. This calculation is performed on a day by day basis for each day in the 4 episodes. After the average contributions are calculated for each day, the highest daily average value across all episodes is selected for analysis. In addition, the highest daily average contribution is expressed as a percent of the downwind area's average ozone >=125 ppb. That is, the highest daily average ''ppb'' contribution is divided by the average of the ozone concentrations >=125 ppb on that day (i.e., the day on which the highest average ppb contribution occurred). For example, if the highest daily average contribution from an upwind State to nonattainment downwind is 15 ppb and the average of the hourly ozone values >=125 ppb on this day in the downwind area is 150 ppb, then the 15 ppb contribution, expressed as a percent, is 10 percent.

CAMx Metric 4: Percent of Total Manmade Ozone Contribution. This metric represents the total contribution from emissions in an upwind State relative to the total ozone for all hours above the NAAQS in the downwind area. This metric, which is referred to as the ''average contribution,'' is calculated for each episode as well as for all four episodes combined. The following example is used to illustrate how this metric is calculated for a single episode for a particular downwind area. In step 1, all predicted Base Case hourly values >=125 ppb in the downwind area are summed over all nonattainment receptors and all days in an episode. In step 2, the ''ppb'' contributions from a source area to this downwind area are summed over all nonattainment receptors in the downwind area and all days in the episode to yield a total ppb contribution. The total contribution calculated in Step 2 is then divided by the total ozone >=125 ppb in the downwind area to produce the fraction of ozone >=125 ppb in the downwind area that is due to emissions from the upwind source area. This fraction is multiplied by 100 to express the result as a percent.

4. Confirmation of States Making a Significant Contribution to Downwind Nonattainment

In the proposal, EPA made findings of significant contribution based on a

[43] As described in the Air Quality Modeling TSD, the metrics calculated using the hourly contributions >= 125 ppb are consistent with the metrics calculated using 1-hour daily maximum contributions >= 125 ppb. Similarly, the metrics calculated using all 8-hour periods >= 85 ppb are consistent with the metrics calculated using 8-hour daily maximum values >= 85 ppb.

weight-of-evidence approach that included consideration of air quality contributions based on subregional modeling. As discussed in section II.C.2, Summary of Notice of Proposed Rulemaking Weight-of-Evidence Approach, EPA believes that the subregional modeling provides an adequate independent basis for determining which States contribute significantly to downwind nonattainment. The evaluation of the State-by-State modeling confirms the overall findings that were based on the subregional modeling and provides more refined information regarding the impacts of specific upwind States on nonattainment in individual downwind areas. This State-by-State modeling is discussed in more detail below.

a. Analysis Approach. The EPA has analyzed the results of the State-by-State UAM–V zero-out modeling and the State-by-State CAMx source apportionment modeling for each of the 23 jurisdictions for which this modeling is available.[44] Both UAM–V and CAMx modeling results are available for fifteen States (i.e., Alabama, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Michigan, Missouri, North Carolina, Ohio, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin). For an additional eight States (i.e., Connecticut, Delaware, the District of Columbia, Maryland, New Jersey, New York, Pennsylvania, and Rhode Island), CAMx modeling is available. Also, as noted above in Section II.C.3, State-by-State Air Quality Modeling, Connecticut and Rhode Island were combined as a single source area, and Maryland, the District of Columbia, and Delaware were also combined as a single source area. Because the NO_X emissions and/or NO_X emissions density is large in each jurisdiction within both of these combined source areas, EPA believes that the downwind contributions from these combined source areas can be attributed to each jurisdiction within the source area.

For the 1-hour NAAQS, EPA evaluated downwind impacts in two ways using the factors described in Section II.C.3, State-by-State Air Quality Modeling. First, EPA evaluated the contributions from each upwind State to nonattainment in each downwind State. Second, the EPA evaluated the contributions from each upwind State to nonattainment in each downwind 1-hour nonattainment area. In downwind States which only contain a single intrastate nonattainment area (e.g., Atlanta), the results of the downwind State and downwind nonattainment area analyses are the same because the same nonattainment receptors are used in both cases. For the 8-hour NAAQS, EPA evaluated the contributions from upwind States to 8-hour nonattainment in each downwind State.

The EPA used the following process in determining whether a particular upwind State contributes significantly to 1-hour nonattainment in an individual downwind area. First, EPA reviewed the extent of the nonattainment problem in the downwind area using ambient design values and model predictions of future ozone concentrations after the application of (a) 2007 Base Case controls, (b) additional local NO_X reductions, and (c) regional reductions (additional local plus upwind NO_X reductions).[45] As indicated above, EPA determined that each downwind area had a residual nonattainment problem even after implementation of the control measures in the 2007 Base Case.

Second, using the information from CAMx Metric 4[46], EPA reviewed (a) the relative portion of the ozone problem in each downwind area that is due to ''local'' emissions (i.e., emissions from the entire State or States in which the downwind area is located), (b) the total contribution from all upwind emissions (i.e., the sum of the contributions from manmade emissions in all upwind States, combined), and (c) the contribution from manmade emissions in individual upwind States. The local versus upwind contributions for each downwind area are provided in the Air Quality Modeling TSD. The EPA analyzed this information to determine whether upwind emissions are an important part of the downwind areas' nonattainment problem. In general, the data indicate that, although a substantial portion of the 1-hour nonattainment problem in many of the downwind areas is due to local emissions, a substantial portion of the nonattainment problem is also due to emissions from upwind States. In addition, for most upwind-State-to-downwind-area linkages there is no single upwind State that makes up all of the upwind contribution. Rather, the total contribution for all upwind States combined is comprised of individual contributions from a number of upwind States many of which are relatively similar in magnitude such that there is no ''bright line'' which distinguishes between the contributions from most of the individual upwind States.

Third, EPA determined whether each individual upwind State significantly contributes to nonattainment in a particular downwind area using the UAM–V and CAMx metrics to evaluate three aspects, or factors of the contribution.[47] These factors include the magnitude, frequency, and relative amount of the contribution. The specific UAM–V and CAMx metrics which correspond to each of the factors are identified in Table II–2. As indicated in the table, there is at least one metric from each modeling technique that corresponds to each of the three factors.

TABLE II–2.—METRICS ASSOCIATED WITH EACH CONTRIBUTION FACTOR

Factor	UAM–V	CAMx
Magnitude of Contribution	Maximum ''ppb'' contribution (Metric 2)	Maximum ''ppb'' Contribution (Metric 2); and Highest Daily Average Contribution (Metric 3).
Frequency of Contribution	Number and percent of exceedences with contributions in various concentration ranges (Metric 1 and 2)	Number and percent of exceedences with contributions in various concentration ranges (Metric 1 and 2).
Relative Amount of Contribution.	Total ''ppb'' contribution relative to the total ''ppb'' that the downwind area is above the NAAQS (Metric 3); and Total population-weighted ''ppb'' contribution relative to the total population-weighted ''ppb'' that the downwind area is above the NAAQS (Metric 4)	Four-episode average percent contribution from the upwind State to nonattainment in the downwind area (Metric 4); and Highest single-episode average percent contribution from the upwind State to nonattainment in the downwind area (Metric 4).

[44] The approach for dealing with the 15 States in the OTAG domain which were not proposed to make a significant contribution to downwind nonattainment are discussed below in Section II.C.5, States Not Covered by this Rulemaking.

[45] Scenarios (b) and (c) refer to the runs used to assess transport as described in Section IV.

[46] This information represents the average contributions across all four episodes. In addition to the four-episode average contribution, EPA also examined the highest single-episode average contribution from each upwind State to each downwind area.

[47] The factors used to interpret the metrics should not be confused with the multi-factor approach used to identify the amounts of NO_X emissions that contribute signficantly to nonattainment.

It should be noted that the relative contributions of individual upwind States to a particular downwind area add up to 100 percent for the CAMx 4-episode average percent contribution. However, this is not the case for the CAMx highest single-episode average percent contribution since the value from one upwind State can occur in a different episode than the value from another upwind State for the same downwind area. In addition, it should be noted that UAM–V Metrics 3 and 4 are used in combination to express the total contribution above the NAAQS relative to the total amount that the downwind area is above the NAAQS. The values for each of these metrics also do not add up to 100 percent when considering contributions from multiple upwind States to an individual downwind area.

The EPA compiled the UAM-V and CAMx metrics by downwind area in order to evaluate the contributions to downwind nonattainment. The data on 1-hour and 8-hour contributions were compiled and analyzed separately. The data were reviewed to determine how large of a contribution a particular upwind State makes to nonattainment in each downwind area in terms of the magnitude of the contribution and the relative amount of the total contribution. The data were also examined to determine how frequently the contributions occur.

The first step in evaluating this information was to screen out linkages for which the contributions were very low, as described in the Air Quality Modeling TSD. The finding of significance for linkages that passed the initial screening criteria was based on EPA's technical assessment of the values for the three contribution factors. Each upwind State that had large and/or frequent contributions to the downwind area, based on these factors, is considered as contributing significantly to nonattainment in the downwind area. The EPA believes that each of the factors provides an independent legitimate measure of contribution. However, there had to be multiple factors that indicate large and/or frequent contributions in order for the linkage to be significant. In this regard, the finding of a significant contribution for an individual linkage was not based on any single factor.

For many of the individual linkages the factors yield a consistent result (i.e., either large and/or frequent contributions or small and/or infrequent contributions). In some cases, however, not all of the factors are consistent. For upwind-downwind linkages in which some of the factors indicate high and/or frequent contributions while other factors do not, EPA considered the overall number and magnitude of those factors that indicate large and/or frequent contributions compared to those factors that do not. Based on an assessment of all the factors in such cases, EPA determined that the upwind State contributes significantly to nonattainment in the downwind area if on balance the factors indicate large and/or frequent contributions from the upwind State to the downwind area.

The EPA's evaluation of the contributions to 1-hour nonattainment in New York City is presented as an example to illustrate this process. The New York City area, which consists of portions of New York, New Jersey, and Connecticut, is designated as a severe nonattainment area under the 1-hour NAAQS. The ambient 1-hour design value in New York City, based on 1994 through 1996 monitoring data is 144 ppb. During the four OTAG episodes, 39 percent of the days are predicted to have 1-hour exceedences in 2007 after the implementation of all CAA controls and Federal measures.[48] Moreover, EPA's air quality modeling of the benefits of regional NO_X strategies, as described in Section IV, Air Quality Assessment, indicates that there would still be exceedences of the 1-hour NAAQS remaining in New York City even with eliminating the significant amounts of emissions required by this NO_X SIP Call.

In the assessment of contributions to New York City, EPA examined the local versus upwind contributions to 1-hour nonattainment in this area, as shown in Table II–3. Local emissions in the New York City nonattainment area are spread among numerous stationary sources, area sources, highway sources, and nonroad sources, each of which contributes only a very small, indeed sometimes immeasurable, amount to New York City's ozone nonattainment problem. Combined, these emissions result in approximately 55 percent of the New York City area's ozone problem. Emissions from States upwind of New York, New Jersey, and Connecticut, on average across all four episodes, contribute 45 percent of the nonattainment problem in New York City is due to. However, no single State stands out as contributing most of the total upwind contribution. The biggest single contributor is Pennsylvania (18 percent) followed by Maryland/Washington, DC/Delaware (5 percent). The total contribution from all Northeast States is 23 percent. A similar amount (22 percent) of the total contribution is due to emissions in those States outside the Northeast. The data in Table II–3 indicate that 19 percent of the 22 percent is fairly evenly divided among ten States, whose contributions range from 1 percent (6 States) to 4 percent (Ohio and Virginia). The remaining 3 percent (i.e., 19 percent vs 22 percent) is from States that each contribute less than 1 percent, on average. The highest single-episode contributions from States upwind of the Northeast range from 1 percent (Tennessee) to 8 percent (Virginia). In general, the contribution data in Table II–3 indicate that a substantial amount of New York City's nonattainment problem is due to the collective contribution from emissions in a number of upwind States both within and outside the northeast. That these upwind contributions are a meaningful part of New York City's nonattainment problem is particularly evident in light of the fact that the contribution to the problem made by New York City itself is comprised of the collective contribution of numerous sources.

TABLE II–3.—PERCENT CONTRIBUTION FROM UPWIND STATES TO 1-HOUR NONATTAINMENT IN NEW YORK CITY [1]

Downwind area: New York City	Percent of total manmade emissions over 4 episodes	Highest single-episode percent contribution [2]
Amount due to "Local" Emissions [3]	55	[4]NA
Total Amount from all "Upwind" States	45	NA
Contributions from Individual Upwind States		
PA	18	19
MD/DC/DE	5	6

[48] This is further described in the Air Quality Modeling TSD.

TABLE II–3.—PERCENT CONTRIBUTION FROM UPWIND STATES TO 1-HOUR NONATTAINMENT IN NEW YORK CITY [1]—Continued

Downwind area: New York City	Percent of total manmade emissions over 4 episodes	Highest single-episode percent contribution [2]
OH	4	6
VA	4	8
WV	3	7
IL	2	3
IN	1	2
KY	1	3
MI	1	4
MO	1	2
NC	1	2
TN	1	1
Total Amount from All Other States, combined	3	NA.

[1] These values are based on CAMx Metric 3 calculated across all 4 episodes.
[2] These values are based on CAMx Metric 3 calculated for each episode individually. These values do not add up to 100 percent.
[3] 3. Total contribution from the State(s) in which the Nonattainment area is located.
[4] 4. Not applicable.

The extent of New York City's nonattainment problem and the nature of the contributions from upwind States were considered in determining whether the values of the metrics indicate large and/or frequent contributions for individual upwind States. Specifically, additional controls beyond the local and upwind NO_X reductions which are part of the regional NO_X strategy may be needed to solve New York City's 1-hour nonattainment problem. Also, the total contribution from all upwind States is large and there is no single State or small number of States which comprise this total upwind portion. In this regard, the contributions to New York City from some States may not appear to be individually ''high'' amounts. However, (as described below) these contributions, when considered together with the contributions from other States (i.e., the collective contribution) produce a large total contribution to nonattainment in New York City.

The EPA evaluated the magnitude, frequency, and relative amount of contribution from emissions in individual upwind States to determine which States contribute significantly to 1-hour nonattainment in New York City. The UAM–V and CAMx metrics which quantify each upwind State's contribution to New York City for each of the three factors are provided in the Air Quality Modeling TSD and described below. Examination of the values for these metrics indicates that the upwind States can be divided into three general groups, based on the magnitude, frequency, and relative amount of contribution. The first group contains those upwind States for which the UAM–V and CAMx metrics all clearly indicate a significant contribution to 1-hour nonattainment in New York City. The second group contains those States for which the CAMx and UAM–V metrics are not quite as consistent, but overall the metrics indicate a significant contribution to 1-hour nonattainment in New York City.[49] The third group contains those States for which the CAMx and UAM–V metrics clearly indicate that the impacts do not make a significant contribution to New York City.

Group 1 Upwind States:

The CAMx and UAM–V metrics all clearly indicate that emissions from Maryland/Washington, DC/Delaware, Ohio, Pennsylvania, Virginia, and West Virginia make large and/or frequent contributions to 1-hour nonattainment in New York City. For Pennsylvania the magnitude of contribution, as indicated by the highest daily average contribution (CAMx Metric 3), is 25 ppb and the relative amount of contribution is 18 percent (CAMx Metric 4). For the other upwind areas, the magnitude of the contributions range from 9 ppb to 15 ppb (CAMx Metric 3, highest daily average contributions) with contributions in the range of 5 ppb to 10 ppb—from Ohio, Virginia, and West Virginia (UAM–V Metric 2, maximum ''ppb'' contribution). In terms of the frequency of the contribution, 7 percent to 11 percent of the total number of grid-hours >=125 ppb in New York City receive contributions of 10 ppb from each of these States (CAMx Metric 1 and 2). Also, the relative amounts of the contribution are in the range of 6 percent to 8 percent (CAMx Metric 4, highest single-episode average percent contribution) and the total contribution from each of three States (i.e., Ohio, Virginia, and West Virginia) is large compared to the total amount of nonattainment, ranging from 8 percent to 11 percent (UAM–V Metric 3).

Group 2 Upwind States:

The CAMx and UAM–V metrics are somewhat less consistent on the extent of contributions from each of 5 States: Kentucky, Illinois, Indiana, Michigan, and North Carolina. None of the metrics for either model indicate extremely low or extremely high contributions. Rather, for these States most of the metrics indicate relatively high contributions while a few metrics indicate relatively low contributions. The rationale used by EPA for evaluating the contributions from these States involved comparing and contrasting each piece of data for these States on an individual ''upwind State-by-upwind State'' basis and as a group (i.e., for all 5 States, together) in order to weigh the relative magnitude and frequency of the contributions for making a determination of significance.

UAM–V Metrics—For each of these 5 States the ''weakest'' factor is the magnitude contribution (UAM–V Metric 2) in that the highest contributions are in the range of 2 to 5 ppb. The other UAM–V Metrics, however, indicate that the contributions from each State are of a larger frequency and relative amount. Specifically, four of these States (Kentucky, Indiana, Illinois, and

[49] For New York City, each of the ''Group 2'' States were found to make a significant contribution. However, this was not the case for all of the Group 2 linkages in other nonattainment areas. For example, the contribution from Kentucky to Philadelphia and the contribution from Tennessee to Baltimore were Group 2 situations in which EPA determined that the contributions were not significant.

Michigan) each contribute 2 to 5 ppb to as many as 3 percent to 4 percent of the exceedences in New York City (UAM–V Metrics 1 and 2). While North Carolina contributes to somewhat fewer exceedences (2 percent), this slight weakness is out-weighed by the relative amount of contribution (UAM–V Metrics 3 and 4) which indicates that the total contribution from North Carolina alone is equivalent to 3 percent of the total ''ppb'' >=125 ppb and 4 percent of the population-weighted ''ppb'' >=125 ppb in New York City. For Indiana, Illinois, and Michigan the relative amount of contribution (UAM–V Metrics 3 and 4) is also relatively high and ranges from 3 percent to 5 percent. The relative amount of contribution from Kentucky is somewhat weaker at 2 percent.

CAMx Metrics—For Illinois, all of the CAMx metrics indicate relatively large and/or frequent contributions, as described below. For Kentucky, Indiana, Michigan, and North Carolina the magnitude of contribution is large, as indicated by the maximum contribution which ranges from 6 ppb (Indiana) to 11 ppb (North Carolina). Also, the highest daily average contribution from Kentucky, Michigan, and North Carolina are all in the range of 5 ppb to 7 ppb. In terms of the frequency of contribution, Indiana and North Carolina contribute in the range of 5 ppb to 10 ppb to 3 percent and 6 percent of the exceedences, respectively, in New York City. For Kentucky, Indiana, Michigan, and North Carolina the relative amounts of contribution is somewhat mixed in that the 4-episode average percent contribution is only 1 percent, but the highest single-episode average percent contributions are higher at 2 percent from both Indiana and North Carolina, 3 percent from Kentucky, and 4 percent from Michigan (CAMx Metric 4).

Overall contributions considering UAM–V and CAMx Metrics—Considering the CAMx and UAM–V metrics, as described below, the majority of the contribution factors indicate that, overall, each of the Group 2 States contributes significantly to 1-hour nonattainment in New York City.

Kentucky—

Metrics indicating relatively high and/or frequent contributions:

—Magnitude of Contribution: the maximum contribution from CAMx is 9 ppb (CAMx Metric 2) and highest daily average contribution is 7 ppb (CAMx Metric 3);
—Frequency of Contribution: 4 percent of the exceedences receive contributions of more than 2 ppb (UAM–V Metrics 1 and 2); and
—Relative Amount of Contribution: the highest single-episode average contribution is 3 percent (CAMx Metric 4).

Metrics indicating relatively low and/or infrequent contributions:

—Magnitude of Contribution: the maximum contribution from UAM–V is 2 ppb; and
—Relative Amount of Contribution: the 4-episode average percent contribution is 1 percent (CAMx Metric 4).

Indiana—

Metrics indicating relatively high and/or frequent contributions:

—Magnitude of Contribution: the maximum ''ppb'' contribution is 6 ppb (CAMx Metric 2);
—Frequency of Contribution: 4 percent of the exceedences receive contributions of more than 2 ppb (UAM–V Metrics 1 and 2) ; and
—Relative Amount of Contribution: the total ''ppb'' contribution is equivalent to 3 percent of total amount of nonattainment (UAM–V Metric 3).

Metrics indicating relatively low and/or infrequent contributions:

—Magnitude of Contribution: the maximum contribution from is 2 ppb (UAM–V Metric 2); and
—Relative Amount of Contribution: the 4-episode average percent contribution is 1 percent (CAMx Metric 4).

Illinois—

Metrics indicating relatively high and/or frequent contributions:

—Magnitude of Contribution: the maximum contribution is 8 ppb (CAMx Metric 2); the highest daily average contribution is 6 ppb;
—Frequency of Contribution: 3 percent of the exceedences receive contributions of more than 2 ppb; and
—Relative Amount of Contribution: the highest single-episode average contribution is 3 percent (CAMx Metric 4); the total ''ppb'' contribution is equivalent to 3 percent of total amount of nonattainment.

Metrics indicating relatively low and/or infrequent contributions:

—Magnitude of Contribution: the maximum contribution from UAM–V is 2 ppb.

Michigan—

Metrics indicating relatively high and/or frequent contributions:

—Magnitude of Contribution: the maximum contribution is 7 ppb (CAMx Metric 2); the highest daily average contribution is 5 ppb (CAMx Metric 3);
—Frequency of Contribution: 3 percent of the exceedences receive contributions of more than 2 ppb (UAM–V Metrics 1 and 2); and
—Relative Amount of Contribution: the highest single-episode average contribution is 4 percent (CAMx Metric 4); the total ''ppb'' contribution is equivalent to 3 percent of the total amount of nonattainment.

Metrics indicating relatively low and/or infrequent contributions:

—Magnitude of Contribution: the maximum contribution from UAM–V is 2 ppb
—Frequency of Contribution: 1 percent of the exceedences receive contributions of 5 ppb or more (CAMx Metrics 1 and 2); and
—Relative Amount of Contribution: the 4-episode average percent contribution is 1 percent (CAMx Metric 4).

North Carolina—

Metrics indicating relatively high and/or frequent contributions:

—Magnitude of Contribution: the maximum contribution is 11 ppb (CAMx Metric 2); the highest daily average contribution is 6 ppb (CAMx Metric 3);
—Frequency of Contribution: 6 percent of exceedences receive contributions of 5 ppb or more (CAMx Metrics 1 and 2); and
—Relative Amount of Contribution: the total ''ppb'' contribution is equivalent to 3 percent of total amount of nonattainment.

Metrics indicating relatively low and/or infrequent contributions:

—Relative Amount of Contribution: the 4-episode average percent contribution is 1 percent (CAMx Metric 4).

Group 3 Upwind States: The CAMx and UAM–V metrics clearly indicate that the emissions from the following States do not make large and/or frequent contributions to 1-hour nonattainment in New York City: Alabama, Georgia, Massachusetts, Missouri, South Carolina, Tennessee, and Wisconsin. The rationale for this conclusion is as follows:

—Magnitude of Contribution: all of these upwind States individually contribute less than 2 ppb to 1-hour daily maximum exceedences in New York City (UAM–V Metric 2); the highest daily average contribution was 1 ppb or less from Alabama, Georgia, and Massachusetts, and 2 ppb from South Carolina, Tennessee, and Wisconsin (CAMx Metric 3); and

—Relative Amount of Contribution: the 4-episode average contributions from Alabama, Georgia, Massachusetts, South Carolina, and Wisconsin are less than 1 percent (CAMx Metric 4); the total contributions from Missouri and Tennessee are each equivalent to 1 percent of the total amount of nonattainment in New York City (UAM–V Metric 3).

Based on the preceding evaluation, EPA believes that emissions in each of the following twelve jurisdictions contribute significantly to 1-hour nonattainment in the New York City nonattainment area: the District of Columbia, Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, North Carolina, Ohio, Pennsylvania, Virginia, and West Virginia.

b. States Which Contain Sources That Significantly Contribute to Downwind Nonattainment. The results of EPA's assessment of the State-by-State UAM–V and CAMx modeling confirms the findings based on subregional modeling that the 23 jurisdictions contribute large and/or frequent amounts to downwind nonattainment under both the 1-hour and 8-hour NAAQS and forms an independent basis for those findings. The specific upwind States which significantly contribute to nonattainment in specific downwind States are listed in Tables II–4 and II–5 for the 1-hour NAAQS and Table II–6 and Table II–7 for the 8-hour NAAQS. The information on the 1-hour contribution linkages are presented by upwind State in Table II–4 and by downwind State in Table II–5. In Table II–4 the upwind States are each listed in the first column and the downwind States to which each upwind State contributes significantly are listed in the second column. In Table II–5, the same information is presented by downwind State. In this table, each downwind State is listed in the first column and the upwind States that contribute to that downwind State are listed in the second column. The 8-hour contribution linkages are presented by upwind State in Table II–6 and by downwind State in Table II–7.

TABLE II–4.—DOWNWIND STATES FOR WHICH UPWIND STATES CONTAIN SOURCES THAT CONTRIBUTE SIGNIFICANTLY TO 1-HR NONATTAINMENT [1]

Upwind state	Downwind states
Alabama	GA, IL*, IN*, MI*, TN, WI*.
Connecticut	ME, MA, NH.
Delaware	CT, ME, MA, NH*, NJ, NY, PA, RI, VA.
District of Columbia	CT, ME, MA, NH*, NJ, NY, PA, RI, VA.
Georgia	AL, TN.
Illinois	CT*, IN, MD, NJ*, NY, MI, MO, WI*.
Indiana	CT*, DE*, DC*, IL*, KY, MD, NJ*, NY, MI, OH, VA*, WI*.
Kentucky	AL, CT*, DC*, GA, IL*, IN, MD, MI*, NJ, NY, MO, OH, VA, WI*.
Maryland	CT, ME, MA, NH*, NJ, NY, PA, RI, VA.
Massachusetts	ME, NH.
Michigan	CT, DC*, MD, NJ, NY, VA*.
Missouri	IL, IN, MI, WI*.
New Jersey	CT, ME, MA, NH, NY, PA, RI.
New York	CT, ME, MA, NH, NJ, RI.
North Carolina	CT*, DC*, GA, KY, MD, NJ, NY, OH, PA, VA*.
Ohio	CT, DE, DC*, KY, MD, MA, NH*, NJ, NY, PA, RI, VA.
Pennsylvania	CT, DE, DC, ME, MD, MA, NH, NJ, NY, RI, VA.
Rhode Island	ME, MA, NH.
South Carolina	AL, GA, TN.
Tennessee	AL, GA, IL*, IN, KY, MI*, OH, WI*.
Virginia	CT, DE, DC, KY*, MD, MA, NH*, NJ, NY, PA, RI.
West Virginia	CT, DE, DC, MD, MA, NJ, NY, PA, RI, VA.
Wisconsin	IL*, IN*, MI* .

[1] States marked with an asterisk (*) are included because they are part of an interstate nonattainment area that receives a contribution from the upwind State. New Hampshire is included because it is part of the combined Boston/Portsmouth area; Connecticut and New Jersey are included because they are part of the New York City area; Kentucky is included because it is part of the Cincinnati area; Delaware is included because it is part of the Philadelphia area; Illinois is included because it is part of the St. Louis area; Illinois, Indiana, Michigan, and Wisconsin are included because they are part of the Lake Michigan area; and Maryland, Virginia, and the District of Columbia are included because they are part of the Washington, DC area.

TABLE II–5.—UPWIND STATES THAT CONTAIN SOURCES THAT CONTRIBUTE SIGNIFICANTLY TO 1-HR NONATTAINMENT IN DOWNWIND STATES [1]

Downwind state	Upwind states
Alabama	GA, KY, SC, TN.
Connecticut	DE, DC, IL*, IN*, KY*, MD, MI*, NJ, NY, NC*, OH, PA, VA, WV.
Delaware	IN*, OH, PA, VA, WV.
District of Columbia	IN*, KY*, MI*, NC*, OH*, PA, VA, WV.
Georgia	AL, KY, NC, SC, TN.
Illinois	AL*, IN*, KY*, MO, TN*, WI*.
Indiana	AL*, IL, KY, MO, TN, WI*.
Kentucky	IN, NC, OH, TN, VA*.
Maine	CT, DE, DC, MD, MA, NJ, NY, PA, RI.
Maryland	IL, IN, KY, MI, NC, OH, PA, VA, WV.
Massachusetts	CT, DE, DC, MD, NJ, NY, OH, PA, RI, VA, WV.
Michigan	AL*, IL, IN, KY*, MO, TN*, WI*.
Missouri	IL, KY.

TABLE II–5.—UPWIND STATES THAT CONTAIN SOURCES THAT CONTRIBUTE SIGNIFICANTLY TO 1-HR NONATTAINMENT IN DOWNWIND STATES [1]—Continued

Downwind state	Upwind states
New Hampshire	CT, DC*, DE*, MD*, MA, NJ, NY, OH*, PA, RI, VA*.
New Jersey	DE, DC, IL*, IN*, KY, MD, MI, NY, NC, OH, PA, VA, WV.
New York	DE, DC, IL, IN, KY, MD, MI, NJ, NC, OH, PA, VA, WV.
Ohio	IN, KY, TN, NC.
Pennsylvania	DE, DC, MD, NJ, NC, OH, VA, WV.
Rhode Island	DE, DC, MD, NJ, NY, OH, PA, VA, WV.
Tennessee	AL, GA, SC.
Virginia	DE, DC, IN*, KY, MD, MI*, NC*, OH, PA, WV.
Wisconsin	AL*, IL*, IN*, KY*, MO*, TN* .

[1] Upwind States marked with an asterisk (*) are considered to significantly contribute to the downwind State because they contribute to an interstate nonattainment area that includes part of the downwind State. New Hampshire is included in the Boston/Portsmouth area; Connecticut and New Jersey are included in the New York City area; Kentucky is included in the Cincinnati area; Delaware is included in the Philadelphia area; Illinois is included in the St. Louis area; Illinois, Indiana, Michigan, and Wisconsin are included in the Lake Michigan area; and Maryland and Virginia are included in the Washington, DC area.

TABLE II–6.—DOWNWIND STATES TO WHICH SOURCES IN UPWIND STATES CONTRIBUTE SIGNIFICANTLY FOR THE 8-HOUR STANDARD

Upwind state	Downwind states
Alabama	GA, IL, IN, KY, MI, MO, NC, OH, PA, SC, TN, VA.
Connecticut	ME, MA, NH, RI.
Delaware	CT, ME, MA, NH, NJ, NY, PA, RI, VA.
District of Columbia	CT, ME, MD, MA, NH, NJ, NY, PA, RI, VA.
Georgia	AL, IL, IN, KY, MI, MO, NC, SC, TN, VA.
Illinois	AL, CT, DC, DE, IN, KY, MD, MI, MO, NJ, NY, OH, PA, RI, TN, WV, WI.
Indiana	DE, IL, KY, MD, MI, MO, NJ, NY, OH, PA, TN, VA, WV, WI.
Kentucky	AL, DC, DE, GA, IL, IN, MD, MI, MO, NJ, NY, NC, OH, PA, SC, TN, VA, WV, WI.
Maryland	CT, DE, DC, ME, MA, NH, NJ, NY, PA, RI, VA.
Massachusetts	ME, NH
Michigan	CT, DC, DE, MD, MA, NJ, NY, OH, PA, WV.
Missouri	IL, IN, KY, MI, OH, PA, TN, WI.
New Jersey	CT, ME, MA, NH, NY, PA, RI.
New York	CT, ME, MA, NH, NJ, PA, RI.
North Carolina	AL, CT, DE, GA, IN, KY, ME, MD, MA, NJ, NY, OH, PA, RI, SC, TN, VA, WV.
Ohio	CT, DC, DE, IN, KY, MD, MA, MI, NJ, NY, NC, PA, RI, TN, VA, WV.
Pennsylvania	CT, DC, DE, ME, MD, MA, NH, NJ, NY, OH, RI, VA.
Rhode Island	ME, MA, NH.
South Carolina	AL, GA, IN, KY, NC, TN, VA.
Tennessee	AL, DC, DE, GA, IL, IN, KY, MD, MI, MO, NC, OH, PA, SC, VA, WV, WI.
Virginia	CT, DE, DC, ME, MD, MA, NJ, NY, NC, OH, PA, RI, SC, WV.
West Virginia	CT, DC, DE, IN, KY, MD, MA, NJ, NY, NC, OH, PA, RI, SC, TN, VA.
Wisconsin	MI.

TABLE II–7.—UPWIND STATES THAT CONTAIN SOURCES THAT CONTRIBUTE SIGNIFICANTLY TO 8-HOUR NONATTAINMENT IN DOWNWIND STATES.

Downwind state	Upwind states
Alabama	GA, IL, KY, NC, SC, TN.
Connecticut	DE, DC, IL, MD, MI, NJ, NY, NC, OH, PA, VA, WV.
District of Columbia	IL, KY, MD, MI, OH, PA, TN, VA, WV.
Delaware	IL, IN, KY, MI, NC, OH, PA, TN, VA, WV.
Georgia	AL, KY, NC, SC, TN.
Illinois	AL, GA, IN, KY, MO, TN.
Indiana	AL, GA, IL, KY, MO, NC, OH, SC, TN, WV.
Kentucky	AL, GA, IL, IN, MO, NC, OH, SC, TN, WV.
Maine	CT, DE, DC, MD, MA, NJ, NY, NC, PA, RI, VA
Maryland	DC, IL, IN, KY, MI, NC, OH, PA, TN, VA, WV.
Massachusetts	CT, DE, DC, MD, MI, NJ, NY, NC, OH, PA, RI, VA, WV.
Michigan	AL, GA, IL, IN, KY, MO, OH, TN, WI.
Missouri	AL, GA, IL, IN, KY, TN.
New Hampshire	CT, DE, DC, MD, MA, NJ, NY, PA, RI.
New Jersey	DE, DC, IL, IN, KY, MD, MI, NC, NY, OH, PA, VA, WV.
New York	DE, DC, IL, IN, KY, MD, MI, NC, NJ, OH, PA, VA, WV.
North Carolina	AL, GA, KY, OH, SC, TN, VA, WV.
Ohio	AL, IL, IN, KY, MI, MO, NC, PA, TN, VA, WV.
Pennsylvania	AL, DE, DC, IL, IN, KY, MD, MI, MO, NJ, NY, NC, OH, TN, VA, WV.
Rhode Island	CT, DE, DC, IL, MD, NJ, NY, NC, OH, PA, VA, WV.

TABLE II–7.—UPWIND STATES THAT CONTAIN SOURCES THAT CONTRIBUTE SIGNIFICANTLY TO 8-HOUR NONATTAINMENT IN DOWNWIND STATES.—Continued

Downwind state	Upwind states
South Carolina	AL, GA, KY, NC, TN, VA, WV.
Tennessee	AL, GA, IL, IN, KY, MO, NC, OH, SC, WV.
Virginia	AL, DE, DC, GA, IN, KY, MD, NC, OH, PA, SC, TN, WV.
West Virginia	IL, IN, KY, MI, NC, OH, TN, VA.
Wisconsin	IL, IN, KY, MO, TN.

c. Examples of Contributions From Upwind States to Downwind Nonattainment. A full discussion of EPA's analysis supporting the determination that specific upwind States contribute significantly to individual downwind States under the 1-hour and 8-hour NAAQS is provided in the Air Quality Modeling TSD. Examples of the types of contributions which link individual upwind States to downwind areas are provided below for the 1-hour NAAQS for the 23 upwind jurisdictions.

—Alabama's Contribution to 1-Hour Nonattainment in Atlanta

Magnitude of Contribution: The maximum contribution is 39 ppb (CAMx Metric 2); the highest daily average contribution is 31 ppb (CAMx Metric 3).

Frequency of Contribution: Alabama contributes at least 10 ppb to 12 percent of the 1-hr exceedences (UAM–V Metrics 1 and 2).

Relative Amount: The total contribution from Alabama is equivalent to 14 percent of the total amount >=125 ppb in Atlanta (UAM–V Metric 3); Alabama contributes 8 percent of the total manmade ppb >= 125 ppb in Atlanta (CAMx Metric 4; 4-episode average percent contribution).

—Connecticut/Rhode Island's Contribution to 1-Hour Nonattainment in Western Massachusetts

Magnitude of Contribution: The maximum contribution is 61 ppb (CAMx Metric 2); the highest daily average contribution is 50 ppb (CAMx Metric 3).

Frequency of Contribution: Connecticut/Rhode Island contribute at least 10 ppb to 100 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: Connecticut/Rhode Island contribute 35 percent of the total manmade ppb >= 125 ppb in Western Massachusetts (CAMx Metric 4; 4-episode average percent contribution).

—Georgia's Contribution to 1-Hour Nonattainment in Birmingham

Magnitude of Contribution: The maximum contribution is 51 ppb (CAMx Metric 2); the highest daily average contribution is 24 ppb (CAMx Metric 3).

Frequency of Contribution: Georgia contributes at least 10 ppb to 11 percent of the 1-hr exceedences (UAM–V Metrics 1 and 2).

Relative Amount: The total contribution from Georgia is equivalent to 12 percent of the total amount >=125 ppb in Birmingham (UAM–V Metric 3); Georgia contributes 3 percent of the total manmade ppb >= 125 ppb in Birmingham (CAMx Metric 4; 4-episode average percent contribution).

—Illinois's Contribution to 1-Hour Nonattainment in New York City

Magnitude of Contribution: The maximum contribution is 8 ppb (CAMx Metric 2); the highest daily average contribution is 6 ppb (CAMx Metric 3).

Frequency of Contribution: Illinois contributes at least 5 ppb to 20 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: The total contribution from Illinois is equivalent to 3 percent of the total amount >=125 ppb in New York City (UAM–V Metric 3); Illinois contributes 3 percent of the total manmade ppb >= 125 ppb in New York City (CAMx Metric 4; single highest episode percent contribution).

—Indiana's Contribution to 1-Hour Nonattainment in Baltimore

Magnitude of Contribution: The maximum contribution is 8 ppb (CAMx Metric 2); the highest daily average contribution is 6 ppb (CAMx Metric 3).

Frequency of Contribution: Indiana contributes at least 5 ppb to 26 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: The total contribution from Indiana is equivalent to 4 percent of the total amount >=125 ppb in Baltimore (UAM–V Metric 3); Indiana contributes 3 percent of the total manmade ppb >= 125 ppb in New York City (CAMx Metric 4; single highest episode percent contribution).

—Kentucky's Contribution to 1–Hour Nonattainment in Baltimore

Magnitude of Contribution: The maximum contribution is 9 ppb (CAMx Metric 2); the highest daily average contribution is 8 ppb (CAMx Metric 3).

Frequency of Contribution: Kentucky contributes at least 5 ppb to 24 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: The total contribution from Kentucky is equivalent to 3 percent of the total amount >=125 ppb in Baltimore (UAM–V Metric 3); Kentucky contributes 5 percent of the total manmade ppb >= 125 ppb in Baltimore (CAMx Metric 4; single highest episode percent contribution).

—Maryland/District of Columbia/Delaware's Contribution to 1-Hour Nonattainment in New York City

Magnitude of Contribution: The maximum contribution is 50 ppb (CAMx Metric 2); the highest daily average contribution is 15 ppb (CAMx Metric 3).

Frequency of Contribution: Maryland/District of Columbia/Delaware contribute at least 10 ppb to 14 percent of the 1-hr exceedences and at least 5 ppb to 38 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: Maryland/District of Columbia/Delaware contribute 5 percent of the total manmade ppb >= 125 ppb in New York City (CAMx Metric 4; 4-episode average percent contribution).

—Massachusetts' Contribution to 1-Hour Nonattainment in Portland, ME

Magnitude of Contribution: The maximum contribution is 79 ppb (CAMx Metric 2); the highest daily average contribution is 67 ppb (CAMx Metric 3).

Frequency of Contribution: Massachusetts contributes at least 10 ppb to 100 percent of the 1-hr exceedences (UAM–V Metrics 1 and 2).

Relative Amount: The total contribution from Massachusetts is equivalent to 100 percent of the total amount >=125 ppb in Portland, ME

(UAM–V Metric 3); Massachusetts contributes 56 percent of the total manmade ppb >= 125 ppb in Portland, ME (CAMx Metric 4; 4-episode average percent contribution).

—Michigan's Contribution to 1-Hour Nonattainment in Baltimore

Magnitude of Contribution: The maximum contribution is 9 ppb (CAMx Metric 2); the highest daily average contribution is 8 ppb (CAMx Metric 3).

Frequency of Contribution: Michigan contributes at least 5 ppb to 7 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: The total contribution from Michigan is equivalent to 5 percent of the total amount >=125 ppb in Baltimore (UAM–V Metric 3); Michigan contributes 5 percent of the total manmade ppb >= 125 ppb in Baltimore (CAMx Metric 4; single highest episode percent contribution).

—Missouri's Contribution to 1-Hour Nonattainment over Lake Michigan

Magnitude of Contribution: The maximum contribution is 19 ppb (CAMx Metric 2); the highest daily average contribution is 12 ppb (CAMx Metric 3).

Frequency of Contribution: Missouri contributes at least 10 ppb to 66 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: The total contribution from Missouri is equivalent to 22 percent of the total amount >=125 ppb over Lake Michigan (UAM–V Metric 3); Missouri contributes 9 percent of the total manmade ppb >= 125 ppb over Lake Michigan (CAMx Metric 4; 4-episode average percent contribution).

—New Jersey's Contribution to 1-Hour Nonattainment in Western Massachusetts

Magnitude of Contribution: The maximum contribution is 30 ppb (CAMx Metric 2); the highest daily average contribution is 23 ppb (CAMx Metric 3).

Frequency of Contribution: New Jersey contributes at least 10 ppb to 100 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: New Jersey contributes 16 percent of the total manmade ppb >= 125 ppb in Western Massachusetts (CAMx Metric 4; 4-episode average percent contribution).

—New York's Contribution to 1-Hour Nonattainment in Western Massachusetts

Magnitude of Contribution: The maximum contribution is 25 ppb (CAMx Metric 2); the highest daily average contribution is 23 ppb (CAMx Metric 3).

Frequency of Contribution: New York contributes at least 10 ppb to 100 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: New York contributes 18 percent of the total manmade ppb >= 125 ppb in Western Massachusetts (CAMx Metric 4; 4-episode average percent contribution).

—North Carolina's Contribution to 1-Hour Nonattainment in Philadelphia

Magnitude of Contribution: The maximum contribution is 10 ppb (CAMx Metric 2); the highest daily average contribution is 9 ppb (CAMx Metric 3).

Frequency of Contribution: North Carolina contributes at least 2 ppb to 4 percent of the 1-hr exceedences (UAM–V Metrics 1 and 2).

Relative Amount: The total contribution from North Carolina is equivalent to 4 percent of the total amount >=125 ppb in Philadelphia (UAM–V Metric 3); North Carolina contributes 2 percent of the total manmade ppb >= 125 ppb in Philadelphia (CAMx Metric 4; single highest episode percent contribution).

—Ohio's Contribution to 1-Hour Nonattainment in Baltimore

Magnitude of Contribution: The maximum contribution is 13 ppb (CAMx Metric 2); the highest daily average contribution is 12 ppb (CAMx Metric 3).

Frequency of Contribution: Ohio contributes at least 5 ppb to 51 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: The total contribution from Ohio is equivalent to 11 percent of the total amount >=125 ppb in Baltimore (UAM–V Metric 3); Ohio contributes 4 percent of the total manmade ppb >= 125 ppb in Baltimore (CAMx Metric 4; 4-episode average percent contribution).

—Pennsylvania's Contribution to 1-Hour Nonattainment in Greater Connecticut

Magnitude of Contribution: The maximum contribution is 28 ppb (CAMx Metric 2); the highest daily average contribution is 23 ppb (CAMx Metric 3).

Frequency of Contribution: Pennsylvania contributes at least 10 ppb to 60 percent of the 1-hr exceedences and at least 5 ppb to 98 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: Pennsylvania contributes 10 percent of the total manmade ppb >= 125 ppb in Greater Connecticut (CAMx Metric 4; 4-episode average percent contribution).

—South Carolina's Contribution to 1-Hour Nonattainment in Atlanta

Magnitude of Contribution: The maximum contribution is 24 ppb (CAMx Metric 2); the highest daily average contribution is 23 ppb (CAMx Metric 3).

Frequency of Contribution: South Carolina contributes at least 5 ppb to 6 percent of the 1-hr exceedences (UAM–V Metrics 1 and 2).

Relative Amount: The total contribution from South Carolina is equivalent to 4 percent of the total amount >=125 ppb in Atlanta (UAM–V Metric 3); South Carolina contributes 2 percent of the total manmade ppb >= 125 ppb in Atlanta (CAMx Metric 4; single highest episode percent contribution).

—Tennessee's Contribution to 1–Hour Nonattainment Over Lake Michigan

Magnitude of Contribution: The maximum contribution is 12 ppb (CAMx Metric 2); the highest daily average contribution is 11 ppb (CAMx Metric 3).

Frequency of Contribution: Tennessee contributes at least 5 ppb to 14 percent of the 1-hr exceedences (UAM–V Metrics 1 and 2).

Relative Amount: The total contribution from Tennessee is equivalent to 6 percent of the total amount >=125 ppb over Lake Michigan (UAM–V Metric 3); Tennessee contributes 10 percent of the total manmade ppb >= 125 ppb over Lake Michigan (CAMx Metric 4; single highest episode percent contribution).

—Virginia's Contribution to 1-Hour Nonattainment in New York City

Magnitude of Contribution: The maximum contribution is 25 ppb (CAMx Metric 2); the highest daily average contribution is 11 ppb (CAMx Metric 3).

Frequency of Contribution: Virginia contributes at least 10 ppb to 11 percent of the 1-hr exceedences and at least 5 ppb to 36 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: The total contribution from Virginia is equivalent to 11 percent of the total amount >=125 ppb in New York City (UAM–V Metric 3); Virginia contributes 4 percent of the total manmade ppb >= 125 ppb in New York City (CAMx Metric 4; 4-episode average percent contribution).

—West Virginia's Contribution to 1-Hour Nonattainment in New York City

Magnitude of Contribution: The maximum contribution is 14 ppb (CAMx Metric 2); the highest daily average contribution is 10 ppb (CAMx Metric 3).

Frequency of Contribution: West Virginia contributes at least 5 ppb to 9 percent of the 1-hr exceedences and at least 2 ppb to 28 percent of the 1-hr exceedences (UAM–V Metrics 1 and 2).

Relative Amount: The total contribution from West Virginia is equivalent to 9 percent of the total amount >=125 ppb in New York City (UAM–V Metric 3); West Virginia contributes 7 percent of the total manmade ppb >= 125 ppb in New York City (CAMx Metric 4; single highest episode percent contribution).

—Wisconsin's Contribution to 1–Hour Nonattainment Over Lake Michigan

Magnitude of Contribution: The maximum contribution is 43 ppb (CAMx Metric 2); the highest daily average contribution is 8 ppb (CAMx Metric 3).

Frequency of Contribution: Wisconsin contributes at least 10 ppb to 11 percent of the 1-hr exceedences (CAMx Metrics 1 and 2).

Relative Amount: Wisconsin contributes 4 percent of the total manmade ppb >= 125 ppb over Lake Michigan (CAMx Metric 4; 4-episode average percent contribution).

d. Conclusions From Air Quality Evaluation of Downwind Contributions. As indicated above, EPA is following a multi-step approach for determining whether emissions from an upwind State significantly contribute to nonattainment downwind. The first step involves an air quality evaluation to determine whether the air quality factors, and particularly the extent of the downwind contributions from emissions in the upwind State, indicate that those contributions are large and/or frequent enough to be of concern under the 1-hour and/or 8-hour NAAQS. The second step, as described below, employs a cost-effectiveness analysis to determine which of the upwind emissions may be eliminated through highly cost-effective controls. Any emissions that may be so eliminated are considered to be emissions that significantly contribute to nonattainment downwind. Finally, to confirm that the emissions considered to significantly contribute, taken as a whole, have a meaningful impact on nonattainment in downwind areas, EPA modeled the air quality effects of eliminating that amount of emissions (see Section IV, Air Quality Assessment, below).

The EPA's conclusions from the first step in this process, the air quality evaluation, is that emissions from sources in each of the 23 jurisdictions listed below make a significant contribution to nonattainment downwind for both the 1-hour and 8-hour NAAQS and interfere with maintenance of the 8-hour NAAQS. This determination was based on two independent sets of analyses, each of which EPA believes provides an independent basis for these conclusions. These two independent analyses are (1) subregional modeling using UAM–V, and (2) State-by-State modeling using CAMx and UAM–V. For the subregional modeling, EPA examined the frequency and magnitude of the impacts from each subregion along with State emissions data and other air quality information to evaluate the contributions from upwind States to nonattainment in downwind areas. For the UAM–V and CAMx State-by-State techniques, a number of measures of ozone contribution, or metrics, were used to assess, from several perspectives, the air quality effect of contributions from sources in different upwind States.

The EPA weighed the results of its analysis of these several air quality metrics to determine which upwind States contain sources whose emissions contribute significantly to downwind nonattainment or maintenance problems. By examining the results of several air quality metrics, EPA assured that no one metric determined whether a State contains sources whose emissions contribute to downwind air quality problems. Rather, the determination of whether an upwind State contained sources whose emissions contribute significantly to a downwind nonattainment problem was based on the extent of the contributions reflected by multiple metrics. The EPA concluded that each set of modeling (i.e., subregional and State-by-State) when considered independently under EPA's weight-of-evidence approach provides a sound technical basis for finding that NO_X emissions from sources in the following 23 jurisdictions make a significant contribution to nonattainment of the 1-hour and 8-hour NAAQS in, or interfere with maintenance of the 8-hour NAAQS by, one or more downwind States:

Alabama
Connecticut
Delaware
District of Columbia
Georgia
Illinois
Indiana
Kentucky
Maryland
Massachusetts
Michigan
Missouri
New Jersey
New York
North Carolina
Ohio
Pennsylvania
Rhode Island
South Carolina
Tennessee
Virginia
West Virginia
Wisconsin

The remaining 15 OTAG States not covered by this final rule are discussed below.

5. States Not Covered by This Rulemaking

In Section VI of the NPR, EPA proposed to find that emissions from sources in the following 15 States in the OTAG region do not significantly contribute to downwind nonattainment under the 1-hour or 8-hour ozone NAAQS, or interfere with maintenance under the 8-hour NAAQS: Arkansas, Florida, Iowa, Kansas, Louisiana, Maine, Minnesota, Mississippi, North Dakota, Nebraska, New Hampshire, Oklahoma, South Dakota, Texas, Vermont (62 FR 60369). The EPA received comments on this section of the NPR and has recently conducted some additional CAMx analyses.[50] The CAMx modeling suggested that further analysis using UAM–V State-by-State modeling would be warranted in order to have a set of information comparable to that for other States that are subject to this rule. In today's rulemaking, EPA is taking no action on whether emissions from sources in these 15 States do or do not contribute significantly to downwind nonattainment, or interfere with maintenance downwind, under either NAAQS. Thus, by today's rulemaking, EPA is not requiring these 15 States to submit SIP revisions providing for NO_X emissions controls to meet a statewide NO_X emissions budget; nor is EPA determining that these States will not be required to make these SIP submissions in the future. The EPA is continuing to review available information on the downwind impacts of these States, including comments submitted on the NPR. In addition, EPA plans to conduct State-by-State modeling to determine whether a SIP revision under section 110(a)(2)(D)(i)(I) should be required from any of these States in the future.

[50] See "Notice of Availability" 63 FR 45032 (August 24, 1998).

The EPA intends to begin this modeling in the fall of 1998.

As discussed in the NPR (62 FR 60318 at 60370), EPA reiterates that these 15 States may need to cooperate and coordinate SIP development activities with other States that are subject to today's action. Also, States with interstate nonattainment areas for the 1-hour standard and/or the new 8-hour standard should cooperate in reducing emissions to mitigate local-scale interstate transport problems (e.g., transport from one State in a multi-state urban nonattainment area to another State in that area) to provide for attainment in the nonattainment area as a whole. The EPA encourages the 15 States to conduct additional analyses on ozone transport recommended by the OTAG Policy Group, which indicated that these States, ''* * * will, in cooperation with EPA, periodically review their emissions, and the impact of increases, on downwind nonattainment areas and, as appropriate, take steps necessary to reduce such impacts including appropriate control measures.''[51]

Comment: A number of commenters supported the proposal to exclude the proposed States, either in general or for specific States. Others opposed the proposal in general, or for specific States.

Response: Because EPA is taking no action on the 15 States at this time, EPA will not respond to comments concerning these States at this time. As discussed above, EPA intends to continue to review ambient air quality data, air quality modeling results, and other technical information on the downwind contribution from all States not found to be significant contributors in today's action.

Comment: Several commenters stated that if EPA revisits which States should be included in the rulemaking, EPA must reopen the public comment period.

Response: The EPA agrees. Because today's action does not propose a change from the NPR concerning which States should be covered, no new comment period is needed at this time. As EPA noted in the NPR, if results from additional modeling and technical analyses indicate that States other than the 22 States (and the District of Columbia) that are the subject of today's action should be required to submit a SIP revision under section 110(a)(2)(D)(i)(I), EPA will publish a new NPR as to any such States and provide an additional comment period.

As also stated in the NPR, in 2007, EPA will reassess transport in the full OTAG region to evaluate the effectiveness of the regional NO_X measures and the need, if any, for additional regional controls.

D. Cost Effectiveness of Emissions Reductions

As discussed above, in today's action, EPA considers control costs in determining whether, and the extent to which, upwind emissions contribute significantly to nonattainment, or interfere with maintenance downwind. The EPA considers cost factors in conjunction with other factors generally related to levels of emissions.

1. Sources Included In the Cost-Effectiveness Determination

This subsection describes the rationale used to determine the cost effectiveness of emissions reductions measures. The EPA evaluates the relative costs of the available control measures using average cost effectiveness, measured as dollars per ton of NO_X reduced relative to a baseline, to identify those emissions reductions that are ''highly cost-effective.'' In performing this evaluation, EPA considers the cost savings of a regionwide NO_X emissions trading system for large electricity generating boilers and turbines (i.e., boilers and turbines serving a generator larger than 25 MWe). As described in this section, EPA has determined that these emissions reductions are highly cost effective on a regionwide basis.

To assure equity among the various source categories and the industries they represent, EPA considered the cost effectiveness of controls for each source category separately throughout the SIP call region. Sources are combined into a common source category if they serve the same general industry (e.g., boilers and turbines that are used by the electricity generation industry are combined in the same category). In general, this means that the sources in the same source category share the same six-digit source code classification (SCC). One exception is in the case of boilers and turbines which are combined and then separated into (1) a category of boilers and turbines serving generators that produce electricity for sale to the grid; or (2) a category of boilers and turbines that exclusively generate steam and/or mechanical work (e.g., provide energy to an industrial pump), or produce electricity primarily for internal use and not for sale. The EPA believes that this categorization better reflects the industrial sectors served.

For each source category, the required emission levels (in tons per ozone season) were determined based on the application of NO_X controls that achieve the greatest feasible emissions reduction while still falling within a cost-per-ton-reduced range that EPA considers to be highly cost-effective (hereinafter also referred to as ''highly cost-effective'' measures). Marginal or incremental costs of control are additional cost-effective measures that may provide important information about alternatives. In particular, incremental cost-effectiveness helps to identify whether a more stringent control option imposes much higher costs relative to the average cost per ton for further control. The use of an average cost-effectiveness measure may not fully reveal costly incremental requirements where control options achieve large reductions in emissions (relative to the baseline).

In this rulemaking, EPA has chosen to focus on an average cost-effectiveness measure in identifying highly cost-effective control options for several reasons. Since EPA's determination for the core group of sources is based on the adoption of a broad-based trading program, average cost-effectiveness serves as an adequate measure across sources because sources with high marginal costs will be able to take advantage of this program to lower their costs. In addition, average cost-effectiveness estimates are readily available for other recently adopted NO_X control measures.

The EPA examined a representative sample of potentially available controls. NO_X controls for this rulemaking were considered highly cost-effective for the purposes of reducing ozone transport to the extent they achieve the greatest feasible emissions reduction but still cost no more than $2,000 per ton of ozone season NO_X emissions removed (in 1990 dollars), on average, for each source category. The discussion below further describes the basis for this cost amount and the techniques used for each category. Many may consider certain controls that cost more than $2,000 per ton of NO_X reduced to be reasonably cost-effective in reducing ozone transport or in achieving attainment with the ozone NAAQS in specific nonattainment areas; however, EPA has determined to focus today's rulemaking on only highly cost-effective reductions. In the future, as EPA continues to consider the impact of ozone transport and the most effective ways to assure downwind attainment, EPA may reconsider whether State NO_X budget levels should be lowered to reflect application of additional controls

[51] OTAG Recommendation: Utility NO_X Controls, approved by the Policy Group, June 3, 1997.

that, although more expensive, are nevertheless cost-effective. In addition, as discussed below, in determining whether to assume reductions from source categories with only a few sources or relatively small emissions, EPA considered administrative efficiency in developing conclusions about whether to assume emissions reductions for these sources.

In determining the cost of NO_X reductions by large electricity generating units (EGUs), EPA assumed an emissions trading system. As discussed in Section IV below, EPA evaluated and compared the likely air quality impacts of this rulemaking with and without a regionwide NO_X emissions trading system for electricity generating sources. This analysis shows that a regionwide trading program causes no significant adverse air quality impacts. Because such a program would result in significant cost savings, EPA's cost-effectiveness determination for large electricity generating boilers and turbines assumes that each State will adopt the lowest cost approach, i.e., the States will elect to include these sources in a regionwide NO_X emissions trading program. However, States retain the option of choosing other, perhaps more expensive, approaches to achieving the necessary reductions. For non-EGU sources in the core group of the trading program, EPA used a least cost method which is equivalent to an assumption of an intrastate trading program. Inclusion of these sources in a regionwide trading program would provide further cost savings. For other source categories for which EPA identified highly cost-effective controls (i.e., internal combustion engines and cement manufacturing), EPA assumed source-specific controls. However, a State may choose to include such categories in the trading program and realize further cost savings.

For the purposes of this rulemaking, EPA considers the following sizes of point sources to be large: (1) electricity generating boilers and turbines serving a generator greater than 25 MWe; or (2) other point sources with a heat input greater than 250 mmBtu/hr or which emit more than one ton of NO_X per average summer day.

In the NPR, EPA based the cost-effectiveness determination on NO_X emissions controls that are available and of comparable cost to other recently undertaken or planned NO_X measures. Table 1 provides a reference list of measures that EPA and States have recently undertaken to reduce NO_X and their average annual costs per ton of NO_X reduced. Most of these measures fall below $2,000 per ton. With few exceptions, the average cost-effectiveness of these measures is representative of the average cost-effectiveness of the types of controls EPA and States have needed to adopt most recently because their previous planning efforts have already taken advantage of opportunities for even cheaper controls. The EPA believes that the cost-effectiveness of measures that EPA or States have adopted, or proposed to adopt, forms a good reference point for determining which of the available additional NO_X control measures can most easily be implemented by upwind States whose emissions impact downwind nonattainment problems.

TABLE 1.—AVERAGE COST-EFFECTIVENESS OF NO_X CONTROL MEASURES RECENTLY UNDERTAKEN

[1990 dollars]

Control measure	Cost per ton of NO_X Removed
NO_X RACT	150–1,300
Phase II Reformulated Gasoline	[52] 4,100
State Implementation of the Ozone Transport Commission Memorandum of Understanding	950–1,600
New Source Performance Standards for Fossil Steam Electric Generation Units	1,290
New Source Performance Standards for Industrial Boilers	1,790

[52] Average cost representing the midpoint of $2,180 to $6,000 per ton. This cost represents the projected additional cost of complying with the Phase II RFG NO_X standards, beyond the cost of complying with the other standards for Phase II RFG.

The Federal Phase II RFG costs presented in Table 1 are not strictly comparable to the other costs cited in the table. Federal Phase II RFG will provide large VOC reductions in addition to NO_X reductions. Federal RFG is required in nine cities with the nation's worst ozone nonattainment problems; other nonattainment areas have chosen to opt into the program as part of their attainment strategy. The mandated areas and those areas in the OTAG region that have chosen to opt into the program are areas where significant local reductions in ozone precursors are needed; such areas may value RFG's NO_X and VOC reductions differently for their local ozone benefits than they would value NO_X reductions from RFG or other programs for ozone transport benefits.

Commenters on the proposal generally agreed with basing the cost-effectiveness determination on the cost effectiveness of other recently undertaken measures. Therefore, EPA has considered controls with an average cost-effectiveness less than $2,000 per ton of NO_X removed to be highly cost effective and has calculated the amounts of emissions that States must prohibit based on application of these controls. Some commenters believed that a more appropriate measure of cost effectiveness was incremental—instead of average—dollars per ton of NO_X removed. Other commenters believed that a more appropriate measure was dollars per ppb of ozone removed from a nonattainment area. The EPA continues to depend on regionwide average dollars per ton of NO_X removed when evaluating what control measures are highly cost-effective for the purposes of this rulemaking.

Table 2 summarizes the control options investigated for each source category and the resulting average, regionwide cost effectiveness.

TABLE 2.—AVERAGE COST EFFECTIVENESS OF OPTIONS ANALYZED [53]

[1990 dollars in 2007]

Source category	Average Cost-effectiveness ($/ozone season ton) for each control option		
Boilers and Turbines Generating Electricity	0.20 lb/mmBtu $1,263	0.15 lb/mmBtu $1,468	0.12 lb/mmBtu. $1,760.
Boilers and Turbines not Generating Electricity	50% reduction $1,235	60% reduction $1,467	70% reduction. $2,140.
Other Stationary Sources [54]	$3,000/ton maximum per source.	$4,000/ton maximum per source.	$5,000/ton maximum per source.
Cement Manufacturing	$1,458	$1,458	$1,458
Glass Manufacturing	$2,020	$2,339	$4,758.
Incinerators	$2,118	$2,118	$2,118.
Internal Combustion Engines	$1,213	$1,213	$1,215.
Process Heaters	$2,860	$2,896	$2,896.

[53] The cost-effectiveness values in Table 2 are regionwide averages. The cost-effectiveness values represent reductions beyond those required by Title IV or Title I RACT, where applicable.

[54] For cement manufacturing, incinerators, internal combustion engines and process heaters, the table indicates that the same control technology (at the same cost) would be selected whether the cost ceiling for each source is $3,000, $4,000, or $5,000 per ton; thus the average cost-effectiveness number for these source categories is the same in each column. For glass manufacturing, the table indicates that additional emissions reductions would be obtained from more effective and more costly control technologies as the cost ceiling increase.

The following discussion explains the controls determined by EPA to be highly cost-effective for each source category.

The EPA has analyzed the implications of each State limiting trading within its borders compared to entering into a common trading program with all other States, provided that States choose to control EGUs at an average level of 0.15 lb/mmBtu. In the case of intrastate trading, EPA found that the average cost per ton of the resulting ozone season NO_X reduction was about $1,499 per ton. This result from the IPM model was for all the States together considering changes in dispatch and other aspects of the future operation of the nation's power system. Individual State results were not provided by the model. As explained below, EPA expects that individual State cost per ton results are likely to be fairly close to this collective result.

For a regionwide budget based on 0.15 lb/mmBtu, EPA's analyses suggest that whether (1) there were individual State trading programs, or (2) a single regionwide trading program, all States experienced a substantial reduction in summer NO_X emissions from Base Case emissions levels. For this to occur, there have to be similar opportunities throughout the SIP call region for highly cost-effective reductions to occur at EGUs. If this were not true, EPA would have found, in the case where there is a single trading program across the entire SIP call region, that some States reduce a much greater share of their NO_X emissions than other States do. The fact that there are similar opportunities for NO_X reductions in each of the States indicates that if there were individual State trading programs in place they would each generally have an average cost effectiveness for reducing ozone season NO_X emissions that is fairly close to the cost effectiveness of trading programs in other States. Therefore, each State is generally likely to have an average cost effectiveness of about $1,550 per ton, the amount we found in the results of the IPM model run for a scenario where each State ran its own trading program.

a. Electricity Generating Boilers and Turbines. For EGUs larger than 25 MWe, the control level was determined by applying a uniform NO_X emissions rate regionwide. The cost-effectiveness for each control level was determined using the IPM. Details regarding the methodologies used can be found in the Regulatory Impact Analysis of this rulemaking. Table 2 summarizes the control levels and resulting cost-effectiveness of three options analyzed.

A regionwide level of 0.20 lb/mmBtu was rejected because though it resulted in an average cost effectiveness of less than $2,000 per ton, the air quality benefits were less than those for the 0.15 lb/mmBtu level which was also less than $2,000 per ton. The results suggest that a regionwide level of 0.15 lb/mmBtu should be assumed for this source category when calculating the amount of emissions that should be considered significant and therefore prohibited in each covered State. This control level has an average cost-effectiveness of $1,468 per ozone season ton removed. This amount is consistent with the range for cost-effectiveness that EPA has derived from recently adopted (or proposed to be adopted) control measures. As discussed later in this preamble, EPA has determined that EGU sources are fully capable of implementing this level of control by May 1, 2003.

The EPA estimates that a control level based on 0.12 lb/mmBtu, has a cost effectiveness of $1,760 per ozone season ton removed, which is within the upper range of cost effectiveness. This estimate is based on the Agency's best estimates of several key assumptions on the performance of pollution control technologies and electricity generation requirements in the future which the Agency thoroughly researched over the last two years. Given that the cost per ton estimate for 0.12 lb/mmBtu trading is much closer to $2,000 than the 0.15 lb/mmBtu trading, EPA is not as confident about the robustness of the results. Also, although EPA is very comfortable that a 0.15 lb/mmBtu trading program beginning in 2003 will not lead to installation of SCR technology at a level and in a manner that will be difficult to implement or result in reliability problems for electric power generation, the Agency's level of comfort is not as high in considering 0.12 lb/mmBtu-based trading.[55] With a strong need to implement a program by 2003 that is recognized by the States as practical, necessary, and broadly accepted as highly cost effective, the Agency has decided to base the

[55] For reasons explained in Section V., below, EPA has determined that May 1, 2003 is the earliest practicable date for achieving the level of emissions reductions EPA selected, and therefore is the appropriate date for achieving these reductions in light of the CAA's attainment date requirements.

emissions budgets for EGUs on a 0.15 lb/mmBtu trading level of control.

It should be noted that the cost-effectiveness values for EGUs were calculated using a slightly older version of the final EGU inventory. Changes made to the inventory and growth assumptions resulted in decreasing the final regionwide allowable emission level for EGUs, under the 0.15 option, to 543,825 tons per year from 563,785 tons per year. Reducing the allowable regionwide emissions increased the average cost-effectiveness value of the 0.15 option from $1,468/ton, to $1,503/ton.

b. Other Stationary Sources. The appropriate cost-effective control level for large non-EGU source categories was determined by evaluating various regulatory alternatives. For industrial boilers and turbines (i.e., boilers and turbines greater than 250 mm/Btu per hour or with NO_X emissions greater than 1 tpd), the control level was determined by applying a uniform percent reduction regionwide in increments of 10 percent. For all other stationary sources, the control level was determined by applying source-category-specific cost-effectiveness thresholds, because trading was not assumed to be readily available for these source categories. Details regarding the methodologies used are in the Regulatory Impact Analysis. Table 2 summarizes the control levels and resulting cost-effectiveness for each option under each category.

Further, for large non-EGUs, the cost-effectiveness determination includes estimates of the additional emissions monitoring costs that sources would incur in order to participate in a trading program. Some non-EGUs already monitor their emissions. In the NPR, EPA had not included monitoring costs in the cost-effectiveness determination because such costs had not been estimated at that time. Since then, EPA has evaluated monitoring system costs. These costs are defined in terms of dollars per ton of NO_X removed so that they can be combined with the cost-effectiveness figures related to control costs. Since monitoring costs do not vary with the level of control, the cost per ton for monitoring varies in accordance with the amount of control being required. For purposes of this analysis, the level of control was assumed to be the level of control used to calculate the budget. Monitoring costs varied from about $150 to $400 per ton of NO_X removed, depending on the type of source category.

The EPA, therefore, determines that: (1) For large non-electricity-generating industrial boilers and turbines, a control level corresponding to 60 percent reduction from baseline levels is highly cost-effective (this percent reduction corresponds to a regionwide control level of about 0.17 lb/mmBtu); and (2) for large internal combustion engines and cement manufacturing sources, a control level corresponding to the application of NO_X reduction technology costing no more than $5,000/ton for each source is, on average, highly cost effective. As indicated in Table 2 and described in detail in the RIA, these control levels are associated with a cost effectiveness of approximately $1,467/ton for boilers and turbines, $1,458/ton for cement manufacturing, and $1,215/ton for internal combustion engines. This results in an average emissions reduction from uncontrolled emissions of 90 percent for internal combustion engines and 30 percent for cement manufacturing sources. The EPA notes that States may include these source categories in the model NO_X budget trading program, further assuring that each source would be able to cost-effectively meet its reduction requirements. The EPA determined that controlling glass manufacturing sources, incinerators, and process heaters was not highly cost-effective because all the options analyzed for these source categories cost more than $2,000 per ton of NO_X removed. Thus, no additional controls are assumed for these sources when determining the significant amounts that must be reduced in each State.

2. Sources Not Included In the Cost-effectiveness Determination

For the following groups of sources, EPA is determining that no additional control measures or levels of control should be assumed in this rulemaking, for the reasons described.

a. Area Sources. In the NPR, EPA noted that control levels for area sources (i.e., sources other than mobile or point sources) could not be determined based on available information concerning applicable control technologies. Comments to the NPR did not identify specific NO_X control technologies that were both technologically feasible and highly cost-effective. Because EPA has no new information on applicable control technologies for area sources, no additional control level is assumed for these sources in this rulemaking. Further discussion concerning area sources can be found in Section III, below, of this preamble.

b. Small Point Sources. For the purposes of this rulemaking, EPA considers the following sizes of point sources to be small: (1) Electricity generating boilers and turbines serving a generator 25 MWe or less, and (2) other point sources with a heat input of 250 mmBtu/hr or less and which emit less than one ton of NO_X per average summer day. In the NPR, EPA stated that the collective emissions from small sources were relatively small (in the context of this rulemaking) and the administrative burden, to the States and regulated entities, of controlling such sources was likely to be considerable. As a result, in the NPR, EPA proposed not to assume reductions from these sources in establishing the State budgets.

Comments to the NPR did not identify specific approaches that would result in significant emission reductions and be administratively efficient in controlling these sources. On the contrary, many comments encouraged EPA to exclude small point sources from any budget calculations for this rulemaking.

Therefore, in today's action, EPA is not assuming additional control levels for these sources. Further discussion concerning small point sources may be found in section III, below, of this preamble.

c. Mobile Sources. In the NPR, EPA noted that it could not identify any additional NO_X controls that States could implement for mobile or nonroad sources beyond those already reflected in the proposed State NO_X budgets that were both technologically feasible and cost-effective, relative to point sources covered by this rule, for the purposes of reducing NO_X. Several commenters stated that the EPA should require States to implement additional reductions for mobile sources. However, these commenters did not identify specific, new, technologically feasible mobile source NO_X controls that were highly cost-effective by the standards of today's action. The EPA has re-examined the availability of mobile source control measures available to States, as discussed in more detail in sections III.D. and III.E. below, and has not identified any such controls that are both technologically feasible and highly cost-effective for NO_X control. Therefore, the States' final NO_X budgets promulgated in today's action do not assume implementation of additional highway or nonroad mobile source controls or expansion of existing controls beyond those described in the NPR. Further discussion concerning mobile sources, including the national measures EPA has assumed for purposes of today's rule, can be found in Section III, Determination of Budgets.

d. Other stationary sources. The EPA does not assume, in this rulemaking, any additional control measures or lower emissions levels for municipal waste combustors because these combustors are already being controlled through MACT regulations. Moreover, no additional control measures were assumed for source categories with relatively small NO_X emissions (e.g., iron and steel mills, nitric acid manufacturing sources, space heaters, lime kilns, recovery plants, and engine test facilities). Further discussion concerning why controls were not assumed for these source categories may be found in Section III of this preamble.

e. Conclusion. The above discussion described the controls for various source categories that EPA considers to be highly cost-effective. The next step in the process is to determine the amounts of NO_X emissions that would be eliminated by applying these highly cost-effective controls to the respective source categories. The EPA considers those emissions to be the amounts that contribute significantly to nonattainment in, or interfere with maintenance by, downwind States. By assuming that reductions of this magnitude should occur, EPA determined the resulting State-specific ''budget.'' Section III, Determination of Budgets describes the process EPA used to determine each State's budget and discusses comments received on the NPR.

E. Other Considerations

As described above, EPA determined the amount of emissions that significantly contribute to downwind nonattainment from sources in a particular upwind State primarily by (i) evaluating, with respect to each upwind State, several air quality related factors, including determining that all emissions from the State have a sufficiently great impact downwind (in the context of the collective contribution nature of the ozone problem); and (ii) determining the amount of that State's emissions that can be eliminated through the application of cost-effective controls. Before reaching a conclusion, EPA evaluated several secondary, and more general, considerations. These include:

• The consistency of the regional reductions with the attainment needs of the downwind areas with nonattainment problems

• The overall fairness of the control regimes required of the downwind and upwind areas, including the extent of the controls required or implemented by the downwind and upwind areas

• General cost considerations, including the relative cost-effectiveness of additional downwind controls compared to upwind controls This section discusses these additional considerations.

1. Consistency of Regional Reductions With Attainment Needs of Downwind Areas

a. General Discussion. Currently, air quality levels in the eastern part of the United States are above the 1-hour NAAQS in various, primarily urban, areas. Air quality levels are also above the 8-hour NAAQS in those same areas, as well as many others.

The OTAG, and subsequently EPA, have conducted region-wide air quality modeling, using the UAM-V model, which shows that in approximately 20 primarily urban areas, the 1-hour nonattainment problem will persist by the year 2007, even after all of the controls specifically required under the CAA as well as Federal measures are implemented.[56] This nonattainment problem that remains after implementation of those mandated controls may be termed ''residual nonattainment.'' For the 8-hour NAAQS modeling shows that under the same circumstances, at least one urban area that is linked to each upwind State will continue to experience residual nonattainment, and significantly more areas will be in nonattainment as well.

Further, as discussed above, OTAG's subregional modeling as well as EPA's CAMx modeling and State-by-State zero-out UAM–V modeling, indicate that upwind States contribute significantly to those downwind nonattainment problems under both standards. In general, under the 1-hour standard, emissions from each upwind State affect at least several, primarily urban, nonattainment areas downwind. For example, each of the midwest/southern States of Ohio, Kentucky, Tennessee, West Virginia, Virginia, and North Carolina affects between five and eight downwind nonattainment areas. Under the 8-hour standard, emissions from each upwind State affect nonattainment problems that comprise an even larger geographic area. For example, Ohio, Kentucky, Tennessee, West Virginia, Virginia, and North Carolina each affect between eight to thirteen downwind States with nonattainment problems.

As described in section IV below, EPA has conducted additional regionwide modeling which shows that upwind reductions comparable to those required under today's rule have an appreciable impact on downwind nonattainment problems under both NAAQS. The downwind impact from each individual upwind State's reductions may be relatively small, but the impact from all upwind reductions, collectively, is appreciable. This regionwide modeling— which employs the UAM–V model relied upon by OTAG and also used by EPA for today's action— indicates that even after implementation of the regional reductions, which help downwind areas make progress toward attainment, certain downwind areas under the 1-hour NAAQS, and numerous downwind areas under the 8-hour NAAQS, will experience residual nonattainment. In addition, under the 8-hour NAAQS, many other areas with nonattainment problems are expected to reach attainment based solely on the regional reductions.

Furthermore, as mentioned earlier, the above-described modeling indicates no upwind States whose required regional reductions, in combination with the other regional reductions and CAA required controls, provide more ozone reduction than is necessary for every downwind nonattainment problem affected by that upwind State to attain under each NAAQS. That is, there is no instance of ''overkill,'' so that none of the upwind reductions required under today's action is more than necessary to ameliorate downwind nonattainment.

b. 8-Hour Nonattainment Problems. As indicated above, the upwind reductions are useful in ameliorating downwind nonattainment under both NAAQS, but they are particularly useful in areas with nonattainment problems under the 8-hour NAAQS because more areas have such problems under that standard. Emissions reductions from each upwind State affect a broader swath of downwind 8-hour nonattainment problems, including problems adjacent to, and further away from, the upwind State. For example, emissions from Ohio affect nonattainment problems in each State adjacent to Ohio, as well as numerous States further away. As noted above, in some cases, the upwind reductions eliminate the downwind nonattainment problem; in other cases, those reductions ameliorate the downwind problem but residual nonattainment remains.

Moreover, under the 8-hour NAAQS, upwind contributions tend to be a particularly large percentage of the downwind nonattainment problem. For example, along the Northeast corridor, cumulatively upwind States including adjacent States, contribute 83 percent of

[56] As described elsewhere, the controls specifically required under the CAA include the controls identified in the modeling baseline, as well as certain Federal controls such as NLEV. These controls do not include any additional reductions that may be required in the local nonattainment areas as part of their attainment demonstrations.

Washington, DC's nonattainment problem; 68 percent of Maryland's nonattainment problem; 65 percent of Pennsylvania's nonattainment problem; and 85–88 percent of each of New Jersey's, New York's, Connecticut's, and Massachusett's nonattainment problems. These high levels of upwind contributions to widespread nonattainment problems—both near to, and far from, the upwind State—indicate that the regional reductions from the upwind areas may be expected to be useful in ameliorating downwind nonattainment under the 8-hour NAAQS.

c. Commenters' Concerns. Commenters argued that in the NPR that EPA failed to demonstrate that the proposed reductions in upwind emissions were necessary for downwind areas to demonstrate attainment. Commenters pointed out the lack of local attainment demonstrations under the 1-hour NAAQS.[57]

The EPA does not believe a local attainment demonstration is required before EPA can call on upwind States to reduce emissions pursuant to section 110(a)(2)(D). The EPA believes that available modeling analyses demonstrate that upwind reductions are necessary to help downwind areas come into attainment. The OTAG and EPA subregional modeling, UAM–V State-by-State zero-out modeling, and the CAMx modeling, described above, link each upwind State's emissions and downwind attainment needs, in a manner that is sufficient to support today's action. To reiterate, under the 1-hour NAAQS, the emissions reductions from each upwind State, combined with other emissions reductions, are needed to reduce downwind nonattainment problems. That need is underlined by the fact that the modeling relied on for today's action indicates residual nonattainment after implementation of all required controls and Federal measures. Even after implementation of the regional reductions, there is residual nonattainment for at least one downwind area linked to each upwind State. The same is true for the 8-hour NAAQS, as noted above.

The EPA recognizes that in the future, additional information may become available that would shed further light on the amount of emissions reductions needed for downwind areas to attain the NAAQS. Local-scale modeling may indicate more precisely the ambient impact of regional and local reductions on downwind nonattainment areas and the amount of any residual nonattainment. Nevertheless, it should be emphasized that the models relied on for today's action are state-of-the-art, and that their various inputs—particularly the inventories—have recently undergone close scrutiny and careful refinement through public comment and expert analysis. Accordingly, EPA believes that the overall model results indicating the general impact of upwind emissions and reductions in emissions should be viewed as valid. Accordingly, EPA believes that it has an adequate base of information to require the regional reductions under the 1-hour and 8-hour NAAQS at this time.

2. Equity Considerations

The EPA believes further justification for today's action is provided by overall considerations of fairness related to the control regimes required of the downwind and upwind areas, including the extent of the controls required or implemented by those areas.

The OTAG and EPA modeling analyses clearly indicate that upwind emissions contribute more than trivial amounts to downwind nonattainment problems. As a result, upwind emitters are exacerbating the health and welfare risks faced by those who live and work in downwind areas afflicted with unhealthful levels of ozone. The EPA believes that the principle of simple fairness applies here: upwind States should reduce their emissions that visit those health and welfare problems upon their downwind neighbors. Otherwise, their downwind neighbors would be obliged to pay additional costs to reduce local emissions beyond what would otherwise be necessary to protect their health from upwind emissions. In EPA's judgment, it is fair to require the upwind sources to reduce at least the portion of their emissions for which highly cost-effective controls are available. Indeed, fairness considerations would point towards requiring upwind reductions even if there were some degree of cost inefficiency.

Further, it should be recognized that the major urban nonattainment areas have been required to incur control costs for ozone precursors since shortly after the 1970 CAA Amendments. In general, over the past quarter of a century, these areas have implemented SIP controls that, in combination with Federal measures, place ozone-related controls on virtually all portions of their inventory of ozone precursors, including VOCs as well as NO_x. The Air Quality Modeling TSD includes descriptions of the control measures in place for several major urban nonattainment areas. Although not every major urban nonattainment area has complied with every CAA requirement for ozone precursors, the major urban nonattainment areas have complied with almost all of these requirements, and the CAA provides remedies to assure complete implementation of the required provisions. These measures have already lead to substantial reductions in ozone levels. By comparison, upwind States have not implemented reductions intended to reduce their impact on downwind nonattainment areas.

3. General Cost Considerations

The EPA also generally considered the cost-effectiveness of additional local reductions in the 1-hour ozone nonattainment areas. The EPA conducted this analysis as part of its Regulatory Impact Analysis, completed under Executive Order 12866, for the rulemaking in which EPA revised the ozone NAAQS, 62 FR 38866 (July 18, 1997). The EPA surveyed the additional VOC and NO_x controls available in areas throughout the country that are expected to be nonattainment under either NAAQS. The EPA ascertained that nationally, on average, these additional measures would cost approximately $4,300 per ton removed during the ozone season. See ''Control Measures Analysis of Ozone and PM Alternatives: Methodology and Results,'' July 17, 1997, table VII–2, p. 56. Although this figure is a national average, it provides a basis to conclude that local reductions may be expected to be more expensive than the approximately $1,500 in cost per ozone-season ton removed for the regional NO_x reductions required in today's rulemaking.

Commenters criticized EPA's proposal to measure cost-effectiveness in terms of cost per ton of emissions removed because it did not take into account the ambient impact downwind of the emissions reductions. Commenters cautioned that under certain circumstances, a high level of emissions reductions upwind may result in high costs (even though cost-effective on a per-ton basis), but relatively little ambient benefit downwind. Commenters emphasized that emissions reductions tend to have the greatest ambient benefit when they are within, or adjacent to, the area with the nonattainment problem. Commenters also said that emissions reductions further upwind have less ambient benefit. Accordingly, commenters stated that EPA's cost-effectiveness

[57] As noted in Section II.A., EPA proposed two analytical approaches, the second of which is the same as EPA is today promulgating. The commenters's criticisms seem to apply equally to both approaches.

justification did not support its proposed reduction requirements.

The EPA acknowledges the concerns expressed by the commenters that focusing solely on the cost effectiveness, defined in terms of cost per ton removed, of the emissions reductions would exclude consideration of the total costs incurred by the upwind sources, and would exclude consideration of the downwind ambient benefits that those costs achieve, compared to the costs of achieving the same ambient impact through either local reductions or more extensive reductions in adjacent upwind areas. The EPA further acknowledges air quality modeling makes clear that reductions in emissions closer to the air quality problem have a greater ambient impact.

However, EPA has not been presented with, nor been able to develop, an accurate comparison of the downwind costs of emissions reductions that would achieve the same ambient impact as the regional reductions required by today's action. The EPA does not have comprehensive information concerning available local measures or their costs or ambient impacts.

However, as a qualitative matter, EPA believes that available evidence indicates that the upwind costs are reasonable not only in light of cost-effectiveness per ton removed, but also in light of the downwind ambient impact of the emissions reductions. Under the 1-hour NAAQS, emissions from each upwind State generally affect several downwind nonattainment urban areas. Thus, matching the total ambient impact of the emissions reductions from the upwind State would require emissions reductions in several downwind areas.[58]

Although presently available information does not permit a useful quantitative comparison of total upwind and downwind costs in terms of their ambient impact, EPA believes that upwind reductions replace local reductions that, on a cost-per-ton removed basis, may be expected to be more expensive. Moreover, it should be recognized that for all of the nonattainment areas under the 1-hour NAAQS, the residents have already incurred substantial control costs to eliminate part of the local contribution to the air quality problem. Under these circumstances, EPA considers it equitable to require the upwind emitters to offset their contribution to the problem through at least the reductions that are the most highly cost-effective—in terms of cost-per-ton removed—rather than require the residents of the downwind area to offset those upwind contributions through even more local control measures.

Furthermore, under the 8-hour NAAQS, the available information—again, on a qualitative basis—indicates that the upwind emissions reductions replace a significantly greater set of local measures. As indicated above, emissions from each upwind State affect a wide swath of downwind areas with nonattainment problems. As a result, the emissions reductions from the upwind State replace local reductions in numerous downwind areas. Moreover, some of these downwind areas are adjacent to the upwind State, while others are further away. Thus, under the 8-hour NAAQS, EPA believes that the qualitative case is even more vivid that the upwind emissions reductions replace substantial and costly local measures.

Finally, with respect to the meteorological phenomenon that upwind reductions have less ambient impact the further away they are from the downwind nonattainment problem: EPA modeled the ambient impact of regional variations in the levels of upwind emissions reductions. This modeling, and its results, are discussed in the Air Quality TSD. In brief, the modeling results indicate that it is neither more cost-effective nor more beneficial to air quality to pursue subregional variations in upwind emissions controls.

4. Conclusion

For the reasons discussed above, EPA believes that adequate information is available to determine, on a qualitative basis, that the upwind reductions required by today's action are reasonable in light of the attainment needs downwind, and that the costs of those reductions are reasonable in light of the costs the downwind areas would otherwise face. For these and other reasons noted elsewhere, EPA believes that requiring the regional reductions in today's notice is a reasonable step to take at this time.

Of course, as more comprehensive information becomes available (including additional modeling, additional information concerning local control options and costs, as well as more refined regional air quality information), EPA will continue to examine the issue of regional transport. In addition, as described in Section III., EPA expects to review the issue of regional transport by the year 2007 and may require additional steps by either the upwind States or the downwind States, or both, to address the issue further. Even so, as noted above, the information that is available provides no evidence that the regional reductions required today may prove not to be needed.

III. Determination of Budgets

The EPA used the highly cost-effective measures identified in Section II.D. above to calculate the amounts of emissions in each covered State that will contribute significantly to nonattainment or interfere with maintenance in one or more downwind States (the ''significant amounts''). This Section further describes issues related to cost-effective controls and the role of these controls in the calculation of budgets.

First, as described earlier in this notice, EPA projected the total amount of NO_X emissions that sources in each covered State would emit, in light of expected growth, in 2007 taking into account measures required under the CAA (the ''2007 base year emissions inventory''). The EPA then projected the total amount of NO_X emissions that each of those States would emit in 2007 if each such State applied these highly cost-effective measures (2007 controlled inventory). The difference between the 2007 base inventory and the 2007 controlled inventory for each covered State is the ''significant amount'' that the State's SIP must prohibit to satisfy section 110(a)(2)(D)(i)(I). Each covered State's 2007 controlled inventory—referred to in this Section as the State's ''emissions budget''—expresses the total amount of NO_X emissions remaining after the State's SIP prohibits the ''significant amount'' of NO_X emissions in that State. Each covered State must demonstrate that its SIP includes sufficient measures (of the State's choice) to eliminate those emissions, and thereby meet its budget, in the time frames discussed later in this notice.

A. General Comments on the Base Emission Inventory

Background: In the NPR, EPA solicited comment on technical information used in revising the 1996 base year emissions inventories and the growth and control assumptions used to develop the 2007 projection year base inventories. The EPA received over 200 comment letters (from industry, associations, States, environmental organizations, and U.S. Congressional representatives) on the condition of 1996 base year and projected 2007 emission inventories. The EPA accepted

[58] Although the reductions required of any one individual upwind State under today's rule may not, by themselves, result in large ambient impacts downwind, those reductions, when combined with reductions from other upwind States, do result in appreciable reductions downwind.

proposed modifications to the extent EPA was able to validate them.

As discussed in the NPR (62 FR 60318), EPA established a 120-day comment period (ending March 9, 1998) to address issues related to the proposed rule. In order to develop revised inventories used to recalculate the budgets for final rulemaking in a timely manner, EPA felt that comments received after the March 9, 1998 deadline would be addressed only if time and resources were available and after directing attention to comments received prior to the end of the comment period. The EPA is legally obligated under the Administrative Procedure Act to respond only to comments timely submitted during the public comment period. Response to comments timely submitted before the end of the comment period fulfills EPA's obligation to 5 U.S.C. 553(c).

Although the Agency was not able to address all comments submitted after March 9, 1998, as discussed in Section III.F.5. of this notice, EPA is allowing commenters an additional opportunity to request revisions to the source-specific data used to establish each State's budget. During this time, EPA will be addressing those comments submitted during the NPR and SNPR comment periods which were not addressed for reasons indicated above, as well as evaluate comments that are submitted per Section III.F.5. of the NFR.

1. Quality

Comment: Commenters suggested that the OTAG inventory may not be of sufficient quality for use in the modeling and budget determinations for the non-EGU point, area, nonroad mobile, and highway vehicle source sectors. The commenters stated that OTAG originally intended the inventories to be used in analyzing ozone transport mechanisms and the effect of possible control measures, not for establishing emission budgets as EPA has proposed. Additionally, as one commenter mentioned, many States had prepared inventories only for their moderate and above nonattainment areas, so that the remainder of the State's counties were supplemented with USEPA data. In contrast to these criticisms, other commenters supported the quality of the inventories and the procedures used in their development.

Response: Under the initial OTAG inventory collection process, the 37 States in the domain provided emission estimates for each entire State. The majority of the supplied data were 1990 State ozone SIP emission inventories, but some States supplied data from later years that reflected significant improvement over the 1990 data. Additionally, OTAG collected point source data from the States to update and revise existing emissions inventories used by OTAG. The result of these efforts was an improved emissions inventory which OTAG utilized for modeling as well as strategy analyses.

The EPA used the final OTAG version of the inventory for the emission estimates in the NPR, and then improved the inventory with data supplied by the States and industry through the public comment period. As a result, the revised emissions inventory is the most accurate available for modeling, strategy analyses, and budget calculation purposes. The inventory has been through numerous versions, each version reviewed and extensively commented on by States, industry, and the public. These inventory data are more accurate than any other data used in the past as the basis for the various State-specific SIP revisions (such as rate-of progress SIP revisions or attainment demonstrations). The EPA considers it sufficiently accurate for purposes of determining the budgets.

The EPA recognizes that emission inventories change as more accurate data or methods are developed for estimating emissions. For inventory changes that may be necessary after final promulgation of the budgets, EPA has a process for determining what changes need to be made as well as how the changes would be made to the inventories. This is discussed in further detail in Section III.F.5. of this notice.

Comment: Several commenters were concerned that the initial State NO_X emissions inventories submitted by the States were never quality-assured or commented upon by the States, the regulated community, or the public. Some commenters suggested the reevaluation of emissions estimates with State, local, and industry support.

Response: Under the guidance of OTAG, the initial emission inventories submitted by the States were quality-assured by technical experts, including State and local emission inventory contacts, industry, EPA staff and contractors, and the OTAG Emission Inventory Technical Committee. As EPA amended and modified the inventory for use in the modeling for the NPR, SNPR, and the budget analyses, additional quality assurance was completed. The most accurate inventory development tools available at the time were used to validate these data and to quality assure emission calculations in these data bases. Existing data sets, including the NET data, the OTC NO_X Baseline emission inventory, EPA'S AIRS/AFS major point source reporting system, and EPA's Emission Tracking System (ETS), which contains data submitted and certified as correct by the States, were used for comparison purposes. Where discrepancies were found, either before, during, or after the public comment period, States and industry were contacted to clarify and support revised emission estimates.

2. Availability

Comment: Commenters asserted that the emissions inventory used for the SIP modeling and budget calculations were not made available for public review along with the proposed rule. One commenter stated that the emissions inventory that forms the basis for the NPR (the SIP Call inventory) did not become available until the first week in February 1998.

Response: On October 10, 1997, EPA posted emissions data on the TTN for use and review during the public comment period (*See* NPR, 60318). These data, in conjunction with the OTAG inventories, were the basis of the initial proposed budgets and modeling analyses in the NPR. Thus, these data were available to the public before the beginning of the 120-day comment period on the NPR, which allowed ample time to develop budget, modeling, and cost analyses for submission during the comment period. By notice dated January 28, 1998 (63 FR 4206), EPA issued a caution that comments on the inventory must be submitted by the March 9, 1998 close-of-public-comment date, so that EPA could finalize the inventories and use them for further analyses.

On February 3, 1998, in response to initial public comments and internal review of the initially released data, draft amendments to the emissions inventory were posted on the EPA's TTN site. These changes included the addition of EGU sources less than or equal to 25 MWe which were excluded from the initial budget calculation, correction of EGU growth factors, and the reclassification to the non-EGU file of some sources previously erroneously identified by OTAG as EGU sources. Erroneously omitted non-EGU point source records were also added to the emissions inventory. Area, highway, and nonroad mobile source information was not modified in this iteration. By posting this data on February 3, 1998, EPA allowed 5 more weeks for public comment on the revised data, until the conclusion of the comment period for inventory data on March 9, 1998. Because the revisions were fairly minor, EPA believes this amount of time was adequate. The EPA did receive comments by March 9, 1998 on the revised data it had posted on February 3, 1998.

B. Electricity Generating Units (EGUs)

Background: To determine the budget for each State's electricity generating sector, EPA developed an inventory of baseline heat input (mmBtu) and NO_X emissions (tons/season) data for each unit. In the NPR, EPA proposed to use the higher, by State, of 1995 or 1996 heat input data to calculate baseline heat input rates (62 FR 60352). The EPA maintained this approach for the SNPR, but added 577 smaller units to the State budget inventories, which had erroneously been omitted for the NPR. These units included electricity generating sources of 25 megawatts of electrical output (MWe) or smaller and additional units not affected under the Acid Rain Program.

1. Base Inventory

Comment: Commenters suggested that using the higher of 1995 or 1996 utilization rates for setting the baseline for the EGU portion of the budget may not be appropriate in all instances. In general, commenters argued for various degrees of flexibility in choosing the baseline year(s) to be used for calculation of budgets.

Response: As discussed below, EPA has made corrections to the baseline heat input data for a small number of EGUs based on careful review of the data supplied with source-specific comments. Using 1997 CEMS data is not a practical option because EPA has not had time to extract from the Acid Rain Emissions Tracking System (ETS) the 5-month ozone season heat input values, quality assure them, or publish them. (Although EPA's Acid Rain Program intends to publish its 1997 Emissions Scorecard later in 1998, this publication will contain only annual, not ozone season, data.) Accordingly, EPA has finalized the EGU portion of the budget for each State using the higher of the 1995 or 1996 ozone season heat input values.

Comment: Commenters asserted revisions were needed to the published heat input data for some EGUs and proposed related additional source-specific changes. Commenters on this issue stated that inaccurate calculations of heat input data resulted in significant errors in the Statewide budgets. Several suggested the need for revision before calculation of final budgets. Many of these commenters provided specific data that they urged EPA to use in the final budget setting process.

Response: The EPA has analyzed the data submitted by these commenters and, where warranted, has made the requested adjustments. Approximately 200 corrections were made to the baseline heat input data for EGU sector inventories.

Comment: Commenters also noted the need to further correct, for some States, the listing of units in the electricity generating sector inventory. Commenters listed specific EGUs that EPA should either include or remove from the inventory, or for which EPA should correct applicable baseline data (e.g., capacity, operating parameters). Several commenters argued that substantial revision of the inventory was necessary before setting budgets under the final rulemaking.

Response: The EPA has analyzed the data submitted by these commenters, including following up with commenters when needed to assure proper interpretation of the data. Where warranted, EPA has corrected the State inventories of units and applicable baseline data.

While the vast majority of corrections consisted of adding small units (e.g., municipal generators and peaking diesel units), combustion turbines, and independent power producers not affected under the Acid Rain Program, some involved deleting units that are no longer operational or have been misclassified and, in actuality, are industrial non-electricity generating boilers. The net result is that EPA has added approximately 800 units to the State EGU inventories. The EPA believes that these inventories are sufficiently accurate to develop a budget.

Comment: Commenters suggested types and sizes of sources to include or exclude from the electricity generating sector inventory. As to the sizes of sources to include in the inventory, commenters on the NPR were roughly split on the inclusion of units less than or equal to 25 MWe. Several noted that emissions from sources below this level were negligible and should not be included. One commenter noted, however, that these sources should be included in the final budget because they tend to operate on peak demand days which frequently correspond to high ozone days. Several suggested that 15 MWe be the cutoff for the utility component of the budget.

On a separate concern, a few commenters disagreed with the inclusion of non-utility power generators in the utility list of sources and proposed that they be included with industrial non-electricity generating unit sources.

Response: Many of these comments appear to confuse discussions of other related issues (e.g., core sources for NO_X cap and trade rule, appropriate sources for cost-effective control) with the types and sizes of EGUs to be included in the baseline inventory for setting the budget. All emissions should be included in the base inventory and, thus, in the budget. As noted previously, using information supplied by commenters, EPA has agreed to add many small units to the base inventories of several States. Concurrently, EPA has also decided not to classify EGUs less than or equal to 25MWe as core sources for the trading program, as discussed in Section VII of this notice, or to assume an emissions decrease for these small units (''cutoff level'') as part of Statewide budgets for EGUs.

The EPA maintains its decision to include industrial units that generate electricity in the definition of EGUs is entirely consistent with the changing, more competitive, character of today's electric power generation industry in the US. Also, these units are amenable to the same NO_X control technologies, at generally the same cost-effectiveness, as utility units.

2. Growth

Background: In the NPR and SNPR, EPA used forecasts of future electricity generation to apply State-specific growth factors in calculating the emissions budgets for the electricity generating sector. In the SNPR, EPA revised the growth factors (the ''corrected'' projections) to account for projected new combustion turbine and combined cycle units inadvertently excluded in the analysis developed in support of the NPR. The EPA also discussed in the SNPR that ''revised'' electricity generation projections could lead to lower growth rates, and therefore lower budgets, and placed supporting information in the docket. However, EPA proposed to use the ''corrected'' projections in calculating State budgets to provide additional compliance flexibility to sources and States (63 FR 25905).

a. Growth Rates.

Comment: The EPA received approximately 36 comments in response to the NPR and roughly 28 comments in response to the SNPR regarding the estimated growth rates that were used to determine the NO_X budget for each State. These comments were submitted by State agencies, associations, utilities, and a public interest group. Commenters expressed concern regarding a number of specific issues, including the following:

(i) the appropriateness of using growth factors to determine the NO_X budget,

(ii) use of the IPM model to establish the growth factors for each State, and

(iii) the use of the ''corrected'' instead of the ''revised'' projections.

Some of these commenters opposed growth factors generally, but many of them supported the concept of—but not the method proposed for—applying a growth factor.

Response: The OTAG's technical analyses of NO_X emissions suggested that EPA needed to consider the electric power industry's future growth in determining the amount of NO_X reduction that would be reasonable for the power industry to make in the future. The OTAG factored the growth of the power industry's emissions from 1990 to 2007 into the air quality analysis that it performed. The results of this analysis were the basis of its recommendations to EPA to lower NO_X emissions from the power industry in many Eastern States. Because the Agency made its predictions about attainment in 2007 based on projections of emissions considering growth, rather than on historical emissions, the Agency also believes that the State budgets to be used up to 2007 should account for growth in electricity demand. Not accounting for growth in demand for electricity would require States to reduce emissions below the level that EPA predicted was necessary to reach attainment. By accounting for growth through 2007 and applying that growth beginning in 2003, EPA essentially allows sources to emit at a slightly higher level than 0.15 lb/mmBtu in the years 2003 through 2006.

In today's action, the Agency has determined to continue to incorporate growth out to 2007 in developing State budgets for summer NO_X emissions. Not accounting for growth would mean that additional control measures—to offset growth—would be required, and EPA has not determined that those additional control measures would be cost-effective. In considering growth, EPA has determined to continue to use either 1995 or 1996 State-wide heat input data, for whichever year was higher for units over 25 megawatts that burn fossil fuels for baseline data. (More details on this approach can be found above in Section III.B.1. Base Inventory).

To estimate growth, EPA considered several options. Ultimately, the Agency has decided to use State-specific growth factors derived from application of the Integrated Planning Model (IPM) using the 1998 Base Case [59] (also referred to as the ''revised'' growth factors). This is the same Base Case used for the Regulatory Analysis in support of the SNPR. The reasons for using these data are discussed below under ''Use of IPM.''

b. Use of IPM.

Comment: Many commenters questioned whether use of the IPM model was appropriate to derive accurate State-specific growth factors. Commenters expressed concern that there was too much variation between each State's individual growth rate as determined by the IPM model, and suggested that use of region-wide IPM growth factors may be more appropriate. They also questioned the reliability and accuracy of the IPM model, especially as applied on an individual State basis. A number of commenters stated that EPA's growth projections were lower than growth rates projected in the context of State utility planning efforts. Several commenters suggested that EPA base its growth rates on projections other than OTAG, or EPA's IPM forecasts; they especially urged the Agency to consider individual State-prepared forecasts. This was to avoid problems that commenters believe exist in EPA's use of the IPM model for forecasting electricity generation in various areas of the country. Specific concerns focused on:

(i) the effect of IPM projections and associated NO_X budgets on future growth within each State, and

(ii) how the IPM model accounts for:

—planned nuclear unit retirements,
—the impact of a deregulated utility marketplace, and
—improvements in energy efficiency and control technology.

Many commenters also generally expressed concern that there is insufficient information or documentation on how EPA used the IPM model to determine growth factors.

Many commenters asserted that EPA should not incorporate the growth factors into the budget calculation process. These commenters argued that adding growth to baseline activity and subsequently applying controls reduces the stringency of the standards, and introduces an unacceptable level of uncertainty. They suggested that the budgets should be based on historic utilization rates, and that States could then determine how to allocate their budgets to provide for growth. These commenters recommended that, if a growth factor must be used, then EPA should apply a uniform growth rate region-wide to determine the NO_X budget for each State.

Response: The EPA initially considered using the OTAG growth rates, but found that they were largely based on past, State-specific generation trends and did not factor in the more competitive electric power market where electricity will be increasingly moving between regions in response to the cost of producing electricity. The Agency also found that there were several other major limitations that were described in the NPR. (62 FR 60352–60353).

The Agency considered setting the State NO_X budgets based on past generation levels in States, but this approach also does not consider how competition in the industry in the future will alter electricity generation practices. It ignores growth and shifts in production altogether. A variant of this approach, suggested by several commenters, would be to use a uniform growth factor for all States based on some projection of future growth through the 23 jurisdictions covered by this rule. This approach appears even-handed, but EPA views it as unfair and inaccurate with respect to States in which:

(i) utilities are particularly economical to operate, and

(ii) the generation of power by these firms is expected to grow at a rate greater than average.

Another similar alternative suggested in the public comments was that EPA use a uniform growth factor for all States in the same region, e.g., the North American Electricity Reliability Council (NERC) regions, or subregions. The problem with this approach is, again, that certain States within the same region are expected to vary in their rate of growth, given differences in their electric utilities. The fact that some States are in several NERC regions also makes this approach less practical.

The Agency looked at several well-recognized forecasts of regional electricity generation growth, such as those provided by NERC, the *Annual Energy Outlook* of the Energy Information Administration (EIA), and Data Resources Incorporated's (DRI) *World Energy Service U.S. Outlook*. None of these modeling systems provides results at the State level. Therefore, the Agency would have to develop ways to apportion these regional predictions to States. The EPA knows of no way to apportion these regional values to States that would resolve the concerns expressed by commenters. Furthermore, the Agency uses the growth rates from IPM to calculate the cost-effectiveness of NO_X emission reductions, as well as to determine NO_X budgets for States. Therefore, using growth rates that are not from IPM would lead the Agency to using one set of State-specific

[59] The Base Case is the condition of the industry in the absence of the SIP call.

generation estimates to develop NO_X budgets and a different set of State-specific generation estimates for determining cost-effectiveness. As a result, EPA's evaluations of future activities of the power industry might not be considered consistent. Finally, although each of these sources provides reasonable electricity generation forecasts, each of the forecasts could be criticized for the assumptions they make in a manner similar to the way commenters have criticized growth factors from IPM.

Some commenters suggested that the Agency use individual State forecasts instead of IPM forecasts, including projections used for State utility planning efforts. The EPA rejected this type of approach for two reasons. First, nothing in the comments suggested to EPA that the State forecasts are more accurate or more reliable than the IPM forecasts. Instead, the State forecasts varied State by State in the way they predicted future electricity generation. Adoption of these forecasts could result in inconsistencies in setting the State budgets. Electricity generation forecasts require making many technical assumptions which, admittedly, lead to some uncertainty in the results. Accordingly, the Agency believes that the fairest way to determine emissions budgets is to handle these assumptions in a consistent way for all of the States, as long as a reasonable approach and reasonable modeling assumptions are used.

Therefore, EPA has decided to use the IPM 1998 Base Case emissions forecast for deciding State NO_X budgets in today's action. The Agency finds it to be the fairest and most reliable overall approach to estimating growth factors. It deals consistently with the technical assumptions that occur in energy forecasting and employs a reasonable set of assumptions in the process of making a forecast. As an added advantage, it has undergone considerable review by the electric power industry over the last two years, and the industry was aware that it might be applied as it is in today's rulemaking. Finally, EPA's use of IPM for forecasting State growth rates provides for overall consistency in forecasting future emissions and estimating the cost-effectiveness of reductions in this rulemaking.

The EPA believes that IPM provides a reasonable forecast of State growth rates because it carefully takes into account the most important determinants of electricity generation growth that are facing the power industry today. These major factors include: regional demands for electricity, the impacts of wholesale competition that lead to changes in market share for various utilities, changes in fossil fuel prices, expected improvements in electricity generation technology, costs of emission control technology, expected changes in generation unit operations and regional dispatch practices to lower production costs, nuclear unit retirements, alteration in planning reserve margins to meet peak demand, and limitations in moving power between regions due to transmission constraints.

An explanation of how EPA uses IPM to address these issues and other important factors is included in EPA's *Analyzing Electric Power Generation under the CAAA*, March 1998 (Docket no. V–C–3). Because EPA's assumptions have been reviewed by the public over the last two years and the Agency has worked with EIA and other groups to improve them in response to comments and new information, the Agency believes that it has made reasonable assumptions for a Base Case forecast of electric power generation.

c. Use of ''Corrected'' Growth Rates.

Comment: Some comments on the SNPR expressed concern that the new ''corrected'' growth factors are artificially inflated and will compromise efforts to improve air quality throughout the region. Some of the commenters suggested that States should have the flexibility to determine how to manage emissions from new sources in the context of the original growth factors and NO_X budgets proposed in the NPR. Some of these commenters also stated that it was unclear why EPA chose to use the ''revised'' projections in its cost analysis but retained the ''corrected'' growth factors in its budget calculations. Other commenters, however, were supportive of the new growth factors and the use of the ''corrected'' projections. Finally, several commenters requested that EPA further explain how the ''corrected'' growth factors were derived and subsequently used to generate the NO_X budgets.

Response: In the NPR, EPA proposed a set of growth factors based upon the 1996 IPM Base Case forecast. In the SNPR, EPA corrected the growth factors used in calculating State budgets to account for new generation that had inadvertently been left out of the original calculations (the ''corrected'' growth factors). On the basis of comments that EPA has received on its assumptions for forecasting electricity generation throughout the country during the last year, the Agency revised a set of key assumptions at the beginning of 1998. These assumptions lead to a better projection of electricity generation nationally, by region, and by State. Therefore, the Agency has decided to use the 1998 IPM Base Case forecast over the 1996 IPM Base Case forecast as the basis for its ''revised'' State growth estimates.

The recent important changes that were incorporated into EPA's use of IPM in 1998 include using the most recent NERC estimate of regional electricity demand; the latest available EIA and NERC generation unit data; updated fuel forecasts; updated assumptions on nuclear, hydroelectric, and import assumptions (with special attention to differences in summer use); and an increase in the level of detail in the model to more accurately capture the transmission constraints that exist for moving power between various regions of the country. The Agency also updated its assumptions on the size and operation of all electricity generation units of utilities and independent power producers (with special attention to cogenerators) and updated its assumptions on planning reserve margins and the costs of building new generation capacity. For this, the Agency relied heavily on information compiled from utilities by NERC and the EIA. Each of these agencies has regular contact with the power industry and has its data reviewed by the power industry. Again, details on these improvements in IPM can be found in EPA's *Analyzing Electric Power Generation under the CAAA*, March 1998 (Docket no. V–C–3).

In the SNPR, EPA used the ''revised'' growth factors in the IPM model in its cost analysis but used the higher, ''corrected'' growth factors to calculate State budgets. The EPA proposed the higher growth factors because the Agency believed that this results in less cost and more flexibility for sources to achieve their budget reductions beginning in 2003. However, some commenters pointed out that EPA had provided sufficient flexibility by accounting for growth to the year 2007 and applying that growth estimate beginning in 2003. These commenters remarked that it was not necessary to add further flexibility by using the higher, but less current and less accurate, ''corrected'' growth rates. They also stated that EPA should use the most up-to-date information available. The EPA agrees and is using the ''revised'' growth rates based upon the 1998 IPM Base Case forecast to calculate the State budgets used in today's final rule.

3. Budget Calculation

a. Input vs. Output.

Background: In the SNPR, the component of each State's budget assigned to electricity generation was determined using the State's total heat input, applicable emission rate (0.15 lb/mmBtu), and projected growth in total heat input to 2007. The Agency solicited comment on an alternative approach to calculating the State's budget using each State's share of the 23 jurisdiction electricity generation (electrical output). The SNPR describes in detail the output-based approach, and its possible benefits as advanced by its proponents (63 FR 25907). The Agency asked for comments on the appropriateness, legality, rationale, and methodology for incorporating the output-based approach when calculating the electricity generation component of each State's budget.

Comments: The Agency received comments both supporting and opposing output-based State budgets. Supporters of output-based budgets asserted:

- An output-based budget would promote competition among different types of electricity providers on an equal basis in a deregulated electric utility industry.
- An output-based budget would promote CO_2, mercury, SO_2 and off-season NO_X reductions beyond what would occur under a system that assigns State budgets based upon input.
- An output-based budget may result in more cost-effective NO_X reductions.
- Issuing output-based budgets is legally permissible.

The commenters opposed to output-based State budgets objected to the allocation of allowances to non-NO_X-emitting units, such as nuclear, hydroelectric, solar, or geothermal power plants. They claimed that this would make compliance more difficult and more costly for fossil-fuel burning sources because fewer allowances would be allocated to them.

Commenters opposed to output-based budgets also claimed that:

- Output-based budgets would not necessarily improve energy efficiency compared to existing incentives, such as fuel costs.
- The output-based State budgets may not result in the same geographic distribution of emissions as would occur under the original budget allocation.
- There could be significant administrative problems with changing the basis of the State budgets.

In addition, some commenters, though in general supporting allocations by output, specifically objected to allocating allowances to nuclear-powered units because they believed that this method would encourage nuclear-powered electrical generation, which, they further believed, would have adverse ancillary impacts on the environment.

The Agency received additional comments on the method of allocating State budgets to sources. Further discussion of these comments can be found in Section VI.C.2 of this preamble.

Response: The EPA has an extensive history of promoting the efficient use of natural resources, particularly energy, through both voluntary and regulatory measures. Key emissions standards, such as the standards for new vehicles and the recently promulgated new source performance standards to new power plants, are written as output-based fuel-neutral performance standards that promote the efficient use of energy. The EPA has begun to work with States to find mechanisms to more directly credit the use of energy efficiency measures in SIP. The EPA also has a number of programs that encourage the use of energy efficient technologies by providing energy users, particularly in the residential, commercial and industrial sectors, with information on the economic and environmental benefits of such technologies.

Although the Agency has concluded, for the reasons stated below, that heat-input-based budgets to States are more appropriate at this time, the EPA intends to work with stakeholders to overcome existing obstacles and to design an output allocation system that could be used by States as part of their trading program rules in their SIPs and by EPA in future allocations to States.

The EPA considered how State NO_X budgets would be changed using the output approaches suggested by the commenters. The EPA revised its State budget calculations using available electrical generation data from the EIA for utility and non-utility generators for the higher electrical generation output of either 1995 or 1996, by State. In Table III–1 below, Column 2 presents the proposed budgets based upon heat input. Column 3 presents the revised budgets based upon heat input and the revised growth factors. Column 4 shows output-based budgets, based upon all electrical generation. Some commenters suggested including fossil-fuel and renewable energy source generation—including hydroelectric, solar, wind, and geothermal generation—but not nuclear generation. These are included in Column 5. One commenter suggested using electrical generation from fossil-fuel only, which is included in Column 6.

TABLE III–1.—STATE BUDGETS BY ENERGY SOURCE BASIS

(Higher of 1995 or 1996 EIA data]

Column 1	Column 2	Column 3	Column 4	Column 5	Column 6
State	Proposed input-based budgets fossil fuel-burning generators	Revised input-based budgets fossil fuel-burning generators	Output-based budgets all generation sources	Output-based budgets—all generation sources except nuclear	Output-based budgets fossil fuel-burning generators
Alabama	30644	29026	34832	35068	32744
Connecticut	5245	2583	7677	5156	4456
Delaware	4994	3523	2392	3214	3417
District of Columbia	152	207	100	133	142
Georgia	32433	30255	32223	31713	30819
Illinois	36570	32045	44253	27888	29602
Indiana	51818	49020	32212	43285	45831
Kentucky	38775	34923	24847	33389	34166
Maryland	12971	15033	13284	12969	13212
Massachusetts	14651	14780	11017	13248	13496
Michigan	29458	28165	32275	32037	32457
Missouri	26450	23923	19790	22700	23498
New Jersey	8191	10863	12764	11227	11470
New York	31222	30273	39503	39440	32114

TABLE III–1.—STATE BUDGETS BY ENERGY SOURCE BASIS—Continued

(Higher of 1995 or 1996 EIA data]

Column 1	Column 2	Column 3	Column 4	Column 5	Column 6
State	Proposed input-based budgets fossil fuel-burning generators	Revised input-based budgets fossil fuel-burning generators	Output-based budgets all generation sources	Output-based budgets—all generation sources except nuclear	Output-based budgets fossil fuel-burning generators
North Carolina	32691	31394	32006	30156	29866
Ohio	51493	48468	39790	47143	50019
Pennsylvania	45971	52006	53450	47014	48476
Rhode Island	1609	1118	2242	3012	3202
South Carolina	19842	16290	23252	14085	13831
Tennessee	26225	25386	26410	26084	24770
Virginia	20990	18258	19091	15700	15567
West Virginia	24045	26439	22853	30708	32527
Wisconsin	17345	18029	15745	16637	16324
Total	563785	542007	542007	542007	542007

The Agency then calculated the effective NO_X emission rate for each State in terms of lb/mmBtu, assuming that the entire electricity generation component of the budgets, as determined by the input or output methods, were allocated to the electric generating units (EGUs). The Agency wanted to evaluate whether the effective NO_X emission rate would be too low to prove feasible absent participation by the State in an interstate NO_X emission trading program. The EPA found that under output-based State budgets from all generation sources, three States would need to impose an effective emission limitation of 0.10 lb/mmBtu or less on their fossil-fuel burning electricity generators (see Column 3 in Table III–2 below). One State would need to impose an emission limitation of 0.07 lb/mmBtu. Such a low effective emission limitation may not be technically achievable if a State chooses not to join an interstate allowance trading program, unless the State requires some sources to shutdown. In contrast, the Agency found that it was feasible and cost-effective to make reductions even without an interstate NO_X trading program under an input-based State budget calculated using a uniform NO_X emission rate of 0.15 lb/mmBtu.

TABLE III–2.—EFFECTIVE EMISSIONS RATES FOR EACH STATE BY OUTPUT BASIS

[Higher of 1995 or 1996 EIA data]

Column 1	Column 2	Column 3	Column 4	Column 5
State	Effective emission rate under input-based budgets (Fossil fuel burning generators) (lb/mmBtu)	Effective emission rate under output-based budgets (All generation)	Effective emission rate under output-based budgets (all generation except nuclear)	Effective emission rate under output-based budgets (Fossil fuel-burning generators)
Alabama	0.15	0.18	0.18	0.17
Connecticut	0.15	0.45	0.30	0.26
Delaware	0.15	0.10	0.14	0.15
District of Columbia	0.15	0.07	0.10	0.10
Georgia	0.15	0.16	0.16	0.15
Illinois	0.15	0.21	0.13	0.14
Indiana	0.15	0.10	0.13	0.14
Kentucky	0.15	0.11	0.14	0.15
Maryland	0.15	0.13	0.13	0.13
Massachusetts	0.15	0.11	0.13	0.14
Michigan	0.15	0.17	0.17	0.17
Missouri	0.15	0.12	0.14	0.15
New Jersey	0.15	0.18	0.16	0.16
New York	0.15	0.20	0.20	0.16
North Carolina	0.15	0.15	0.14	0.14
Ohio	0.15	0.12	0.15	0.15
Pennsylvania	0.15	0.15	0.14	0.14
Rhode Island	0.15	0.30	0.40	0.43
South Carolina	0.15	0.21	0.13	0.13
Tennessee	0.15	0.16	0.15	0.15
Virginia	0.15	0.16	0.13	0.13
West Virginia	0.15	0.13	0.17	0.18
Wisconsin	0.15	0.13	0.14	0.14

Advocates of an output-based approach contend that individual sources would have the greatest incentive to improve their efficiency, relative to all other sources in the program, if both State budgets and individual source allocations were on an output basis and were updated periodically. For example, if a company replaces a turbine with a more efficient one, the unit supplying the turbine would reduce the amount of fuel (heat input) the unit combusts and would reduce NO_X emissions proportionately, while the associated generator would produce the same amount of electricity. Thus, the company would receive the same allowances if an output-based allocation were updated after the efficiency improvement. This same company would receive fewer allowances under a system that reallocates based on heat input after the efficiency improvement. The company would keep the same allowance allocation if it had a permanent allocation, based upon either heat input or output. With a permanent allocation, the company would have more allowances available than before its efficiency improvements because of its emission reductions, but fewer allowances than if it had greater electrical output recognized through an updated allocation. Thus, of the four approaches, an updated allocation based upon output gives the greatest incentive for improving efficiency in electricity generation.

To provide an incentive within the State budget determinations for improving efficiency over time, EPA would need to issue the State budgets based upon output and periodically update those State budgets. However, many industry commenters wanted long-term or permanent allowance allocations to allow for compliance planning. Updates to the State budgets would require States to reallocate allowances to their sources. In addition, States (both upwind and downwind) would find it easier to manage their resources for improving air quality if they receive a fixed budget for a period of years. With a fixed budget, a State would have the choice of whether to periodically adjust allocations rather than being required to periodically reallocate allowances to its sources.

Finally, the Agency continues to have concerns about data available to establish the baseline for an output-based State budget. The EIA withholds some of the electricity generation information it collects from non-utility generators in order to protect source confidentiality. Therefore, part of the generation data required to establish State budgets is not available to EPA. Thus, EPA would have difficulty in computing and defending State budgets.

In addition, some units are cogenerators, which are electrical generators that divert part of their heated steam to provide heat (steam output), rather than to generate electricity. Information on steam output from cogenerating units or from industrial boilers is not currently available to EPA. A cogeneration unit that was included under the State budget as an electricity generating unit based upon heat input would only have its electrical output included in an output-based State budget, ignoring the portion of heat input used to generate steam output. Thus, output-based State budgets based on currently available data could inadvertently underallocate budgets to States with many cogenerators, which are some of the most efficient units. This could actually discourage improvements in efficiency through cogeneration.

For the reasons stated above, the Agency concludes that it is not appropriate to develop output-based State NO_X emission budgets at this time. However, the Agency does believe that output-based allocations to sources could provide significant benefits. As stated earlier in this Section, the EPA intends to work with stakeholders to overcome existing obstacles and to design an output allocation system based on electricity and steam generation that could be used by States as part of their trading program rules in their SIPs. In addition, EPA is proposing FIPs for States that do not submit adequate SIPs by the deadline required by this final rulemaking. As part of its proposal, the Agency is soliciting comment on source allocations for each State based upon both input and output. While EPA believes that the output data are not sufficiently complete or accurate to use for final budgets or for final source allocations at this time, the Agency is taking comment on the proposed allocations in order to receive public comment and to develop more accurate and more complete output data that could be used in the final FIP rulemaking.

The EPA does believe that, over the long-term, it should continue to look at the issues that surround the use of output-based allocations. In addition, as stated in Section III.B.5. of this preamble, the Agency will review the progress of States in meeting their budgets in 2007. In that review, the Agency will consider not only whether the SIPs achieved the reductions that had been projected to meet the budgets, but also issues such as future budget levels and allocation mechanisms including shifting to an output-based allocation method.

b. Alternative Emission Limits.

Comments: The EPA received numerous comments on the proposed uniform control level of 0.15 lbs/mmBtu for the EGU sector assumptions across the 23 jurisdictions. Many States supported this proposed control assumption. The EPA also received a number of alternative proposals. These contain emission-reduction assumptions ranging from 0.12 lb/mmBtu to be implemented on the schedule proposed in the NPR to a phased approach that starts with 0.35 lb/mmBtu to be implemented by sector and provides for further evaluation of the need for more stringent levels. The latter commenters based their recommendations on their views that emissions from upwind States do not have an ambient impact that is as important as EPA believes, or that implementation of the EGU control levels proposed by EPA would not be feasible by the date EPA proposed. In addition, a number of utilities and other commenters voiced concern that the proposed control assumption of 0.15 lb/mmBtu would be too stringent to provide sufficient surplus allowances for trading.

Response: At the time of the proposal, EPA chose 0.15 lb/mmBtu as the assumed uniform control level for EGUs because it provided the greatest air quality improvements feasible and was cost-effective because its cost ($1,700 per ton NO_X removed in the 5-month ozone season) was, on average, within the cost range of other controls that had been recently promulgated or proposed. The EPA also investigated the costs of several alternative uniform control options: 0.25, 0.20, and 0.12 (though 0.12 resulted in lower emission levels, its average cost-effectiveness calculated at the time of the proposal was $2,100/ton, exceeding EPA's target cost range of $1,000 to $2,000/ton).

Subsequent to the NPR and SNPR, EPA updated its EGU costing model (IPM) and revised stationary source emission inventories (based on public comment). These revisions and corrections lowered the average cost of compliance for all the control levels considered. Additionally, EPA conducted extensive air quality modeling of a number of alternative control levels. The results of the air quality analyses were examined using a number of different metrics for both the one-hour and eight-hour standards. These air quality analyses are discussed in more detail in Section IV of this notice.

The revised air quality analyses show that there is no ''bright line'' to illustrate at what control levels the air quality benefits begin to diminish. The air quality metrics suggest there are corresponding incremental air quality improvements at every incremental control level. For example, tightening the control level improves ozone levels in many non-attainment areas and leads to additional counties achieving attainment under the one-and eight-hour standards. All metrics analyzed show that as the control level moves from 0.25 to 0.20 to 0.15 to 0.12 lb/mmBtu, air quality benefits increase. The analyses also show that none of the alternative control options results in attainment of the ozone standard in all nonattainment areas.

The EPA did not select levels higher than 0.15 lb/mmBtu (such as 0.20 lb/mmBtu or higher) because the 0.15 lb/mmBtu level offers more air quality benefits at a cost that is still highly cost-effective. Moreover, EPA did not have information to indicate that these higher levels could be implemented meaningfully sooner than controls at the 0.15 lbs/MmBtu level. The EPA acknowledges that the 0.12 lbs/MmBtu emission level is also within the average cost-effectiveness range based on the revised cost analysis. The incremental cost-effectiveness of this option is $4,200 per ton, an incremental cost per ton which is 85 percent higher than that for the 0.15 lb/mmBtu level. However, for reasons explained Section II.D., the EPA is not relying on this emission level.

The revised IPM analyses project that under the 0.12 control option, 54 percent of affected EGU capacity should install selective catalytic reduction (SCR) and 41 percent should install selective non-catalytic reduction (SNCR). The installation requirements for SNCR are significantly less extensive than for SCR. The analysis of the 0.15 lb/mmBtu control option projects 31 percent of affected EGU capacity should install SCR and 54 percent should install SNCR. Further, the technical record provides many examples in the United States and internationally of the ability of coal-fired units to achieve emission levels below 0.15 lb/mmBtu with the installation of SCR. The record contains fewer international examples, and only one US example, of a coal-fired unit's ability to achieve emission levels below 0.12 lb/mmBtu.

In terms of the proposed level of control on which the trading program budget is based, EPA believes that trading at 0.15 lb/mmBtu is feasible because the proposed limit can readily be achieved by gas and oil-fired boilers. In fact, more than 50 percent of gas and oil-fired boilers already operate at NO_X levels below 0.15 lb/mmBtu and should readily be able to generate emission credits if affected States join a trading program.

The EPA recognizes that for coal-fired boilers to operate at or below a 0.15 lb/mmBtu emission limit, SCR would generally be necessary. Under a trading scenario, however, if one coal-fired boiler is able to emit below 0.15 lb/mmBtu by installing SCR, it can provide emission credits to another coal-fired boiler and obviate the need for that second boiler to install SCR.

A remaining issue is whether SCR can achieve NO_X levels below 0.15 lb/mmBtu. The EPA believes that SCR technology is capable both of reducing NO_X emissions by more than 90 percent and reducing NO_X rates below the proposed 0.15 lb/mmBtu limit, provided the appropriate regulatory incentive (i.e., emission limit or economic incentive) exists. As discussed in EPA's recent report, ''Performance of Selective Catalytic Reduction on Coal-Fired Steam Generating Units,'' emission rates below 0.15 lb/mmBtu are currently being achieved by a number of coal-fired boilers using SCRs. Examples include: (1) Three Swedish boilers achieving rates between 0.04 and 0.10 lb/mmBtu; (2) six German boilers achieving rates between 0.08 and 0.14 lb/mmBtu; (3) two Austrian boilers achieving rates between 0.08 and 0.12 lb/mmBtu; and (4) four U.S. boilers achieving rates between 0.07 and 0.14 lb/mmBtu. The EPA also recognizes that these boilers, with the exception of the Swedish boilers, have SCR systems designed to achieve target emission limits. As a result, they fail to provide an accurate picture of the emission levels which SCR is capable of achieving below the target emission threshold. For this reason, EPA cannot confidently conclude that enough units can feasibly achieve levels at 0.12 lbs/MmBtu. In summary, EPA believes that an emission rate of 0.15 lb/mmBtu reflects the greatest emissions reduction that EPA can confidently conclude is feasible and that is highly cost-effective, and provides ample allowances to sustain a market under the NO_X Budget Trading Program.

c. Consideration of the Climate Change Action Plan.

Background: The President's Climate Change Action Plan (CCAP) calls for implementation of over 100 voluntary programs aimed at reducing greenhouse gas emissions. A large number of them are aimed at reducing future electricity demand throughout the country. Already, some of these programs have shown striking results in accomplishing their energy efficiency objectives.

Comment: Two commenters noted that it is inappropriate for EPA to incorporate assumed reductions in energy use based on the voluntary measures of the CCAP, which are not binding like a regulation.

Response: The EPA believes that it is appropriate to incorporate the impact of the voluntary measures in the CCAP on future electricity demand. The EPA has always believed that it is appropriate to incorporate any reasonable assumptions that the Agency can support that will affect future electricity demand, or electricity generation practices, into its Base Case forecast. For example, improvements in electricity generation technology, fuel prices changes, and other types of assumptions that are important elements of EPA's forecast of electricity generation and resulting air emissions are also not mandated by regulation. The Agency has considered the impact of the CCAP in using the IPM model for analysis since 1996, and documentation of the assumptions that the Agency has been making have been available for public review since April 1996. Until now, there have been no challenges to this consideration in the numerous reviews that there have been of EPA's documentation of how it uses the IPM model. Also, no one has challenged EPA's specific approach to factoring the CCAP into its electricity generation forecast. (This can be confirmed by examination of the dockets for the Clean Air Power Initiative and the Phase II Title IV NO_X Rule, records of EPA's Science Advisory Board, and the records of the Ozone Transport Assessment Group meetings.)

The EPA updated its assumptions in IPM for the CCAP at the beginning of 1998. The EPA updated its assumptions in the same manner as it has done in the past—by lowering the most recent NERC demand forecast by the amount of electricity demand between 2000 and 2010 that the best available analysis suggests will occur due to the activities in CCAP. The EPA used the in-depth evaluation of the future implications of the CCAP for reducing electricity demand that was the basis for the findings in the Administration's Climate Action Report, July 1997. The amount of demand reduction that occurs appears in Analyzing Electric Power Generation under the Clean Air Act, March 1998. The Climate Action Report analysis was reviewed extensively within the Federal government by EPA, the Department of Energy and other Federal agencies, and the report was reviewed publicly before its publication. The EPA has not received criticism that it has overstated the electricity demand reductions that are the basis for the carbon reductions under the CCAP.

Notably, the electricity demand reductions were distributed evenly throughout the United States, and therefore have no influence on the share of the total amount of NO_X emissions that each State receives. Furthermore, the Agency examined the implications on its cost-effectiveness determination of not including the CCAP reductions in its electricity demand forecast. The EPA found that even if the Agency did not assume the CCAP reductions, it was still highly cost-effective to develop a regional level NO_X budget for the electric power industry, based on the level of control that EPA has assumed. (These results appear in Chapter 6 of the Regulatory Impact Analysis for the Regional NO_X SIP Call, September 1998.)

C. Non-EGU Point Sources

Background: The EPA developed the NO^X SIP call emissions inventory for non-EGU point sources based on data sets originating with the OTAG 1990 base year inventory. The OTAG prepared these base year inventories with 1990 State ozone SIP emission inventories, and EPA supplemented them with either State inventory data, if available, or EPA's National Emission Trends (NET) data if State data were not available.

For the SNPR, non-EGU point source inventory data for 1990 were then grown to 1995 using Bureau of Economic Analysis (BEA) historical growth estimates of industrial earnings at the State 2-digit Standard Industrial Classification (SIC) level. These emissions were grown to 1995 for the purposes of modeling and to maintain a consistent base year inventory with the EGU data. Because BEA data are historical documentation of industry earnings, EPA considered these to be among the best available indicators of growth between 1990 and 1995 (63 FR 25915). Once the common base year of 1995 was established for these source categories, the BEA growth assumptions utilized by OTAG were used to estimate the 2007 base case inventory.

1. Base Inventory

Comment: The majority of comments related to the non-EGU point source inventory alleged that these inventories were incomplete or inaccurate. The comments generally addressed missing sources, non-existent or retired sources, incorrect source sizes, mis-classification of processes, or emission allocation inconsistencies. Many of these commenters provided specific adjustments to be made to the inventories, including emissions modifications, activity factors, source sizes, and facility name changes. A number of States supplied completely new inventories to replace what was in the proposed data sets. Other commenters made broad, general categorical comment on the quality of the inventories with no supporting data.

Response: As was followed under the OTAG inventory update procedures, all State supplied comments were generally incorporated ''as is'' with the understanding that each State quality-assured its own data before submission. Industry-supplied comments were forwarded to respective State agencies for review and where data were deemed appropriate for inclusion, integrated into the inventories. In some instances, States responded that the data provided by the State should override that supplied by industry, or vice-versa. Comments were, in some cases, not incorporated when necessary to prevent double counting of emissions in point and area source inventories, where base year emission modifications were calculated from permitted emission levels and not actual operating activity, where additional supporting data could not be provided by the commenter, or where comments were general characterizations of inventories or inventory sectors. Note that even after State review, if the EPA felt that the data, procedures, methodologies, or documentation provided with the comment were not sufficient, valid, or justifiable, comments, or portions thereof, were excluded from the revision.

Both 1990 and 1995 base year emission and growth modifications were submitted and where 1990 data were provided, the methods described earlier in this Section were utilized to account for growth to 1995 and 2007 levels.

2. Growth

Comment: Several commenters suggest that the growth factors used to determine 2007 non-EGU point source base year inventories are inaccurate or inconsistent across regions and categories of the inventory. They explained that if growth factors are to be used to estimate future base year emissions, consistent national or region-wide values should be utilized for all categories across all States within the domain. This, they continue, would promote equitable potential progress to all areas and not penalize those that have shown past poor growth rates. Some commenters go on to state that growth rates based on past growth automatically disadvantage States which have suffered from unusually low growth rates. In addition to growth rates, some commenters provided 2007 base year emission estimates either with or without the growth and control information needed to validate their calculation.

Response: As noted above, EPA relied on BEA State-specific historical growth estimates of industrial earnings at the 2-digit SIC level as among the best available indicators of growth for non-EGU point sources. The BEA projection factors assume the continuance of past economic relationships. These factors are published every five years and adjusted to account for recent production and growth trends. For this reason, BEA data provide a useful set of regional growth data that EPA recommends for use in preparing emission inventory projections. It is true that BEA projection factors differ among different areas and different source categories because of historical differences in industrial growth among those different areas and source categories. However, in general, these projection factors offer the most reliable indicators of future growth as are available.

In cases where commenters questioned the use of EPA's growth rates but provided no alternative of their own, EPA had little choice but to continue to use the BEA-derived growth rates. Some commenters provided alternative or supporting information for modification of source category or State growth estimates. In those cases where a State or industry may have had more accurate information than the BEA forecast (e.g., planned expansion or population rates), data were verified and validated by the affected States and by EPA, and revisions were made to the factors used for that category.

3. Budget Calculation

Background: In the NPR and SNPR, EPA proposed that EGUs with a capacity less than or equal to 25 MWe or 250 mmBtu/hour would be considered small sources (''cutoff level'') and, as such, EPA would not assume an emissions decrease as part of the Statewide budget for this group of sources. At the same time, EPA proposed 2 cutoff levels for industrial (non-EGU) boilers and turbines: units with a capacity greater than 250 mmBtu/hour were defined as large units subject to a 70 percent emission reduction assumption; units with a capacity less than or equal to 250 mmBtu/hr but with emissions greater than 1 ton/day were defined as medium units subject to reasonably available control technology (RACT); and units with a capacity less than or equal to 250 MmBtu/hr and with emissions less than or equal to 1 ton per day were considered small sources for which no reduction would be assumed in the budget. In the SNPR, EPA specifically invited comment on the size cutoffs and on treating large industrial combustion sources (greater than 250 mmBtu or approximately 1 ton per day) at control levels equal to that for EGUs (63 FR 25909). As described below, this approach has been modified somewhat in response to comments and further analysis.

a. Proposed Control Assumptions.

Comments: Some comments supported EPA's proposed approach of assuming 70 percent and RACT controls in its calculation of the budgets. Numerous comments were received stating that the 70 percent reduction is inappropriate, may not be cost-effective and may not be achievable, especially for the following industries: cement plants; municipal waste combustors; certain pulp and paper operations, including lime kilns and recovery furnaces; glass manufacturing; steel plants; and some industrial boilers. Some comments suggested a control level of 60 percent rather than 70 percent. On the other hand, one commenter stated that SCR and SNCR are applicable and have been installed on hundreds of industrial sources.

Response: The EPA generally agrees that 70 percent emissions reduction is not appropriate for all large sources or all large source categories, even though SCR and SNCR are applicable and cost-effective for many sources. Instead of applying a one-size-fits-all percentage reduction to all large non-EGU sources, the specific emissions decreases assigned to each of these source categories for purposes of budget calculation in the final SIP Call rulemaking reflect the specific controls available for each source category that achieve the most emissions reductions at costs less than an average of $2,000 per ton. As described elsewhere in this notice, EPA's analysis results in calculating budget reductions ranging from 30 percent to 90 percent for several source categories and no controls to several other source categories.

b. Small Source Exemption.

Comments: In general, commenters were supportive of EPA including a cutoff level as part of the budget calculation; however, there were many suggestions on what the cutoff should be. The EPA received numerous comments supporting the proposed cutoff level of 25 MWe for EGUs, which is approximately equivalent to 250 mmBtu/hr or one ton per day. In addition, EPA received a few comments supporting a 250 mmBtu/hr cutoff for non-EGU point sources. Commenters indicated that the levels were appropriate and that it was important to be consistent with cutoff levels in the OTC's NO_X trading program. The Ozone Transport Commission (OTC) comprises the States of Maine, New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island, New York, New Jersey, Pennsylvania, Maryland, Delaware, the northern counties of Virginia, and the District of Columbia. In September 1994, the OTC adopted a memorandum of understanding (MOU) to achieve regional emission reductions of NO_X. These reductions are in addition to previous OTC state efforts to control NO_X emissions, which included the installation of reasonably available control technology. The OTC's NO_X trading program requires utility and nonutility boilers greater than 25 MWe or 250 mmBtu to reduce emissions in order to meet a NO_X budget and allows emissions trading consistent with that budget. These NO_X reductions will take place in two phases, the first phase beginning on May 1, 1999 and the second phase on May 1, 2003.

Some comments suggested assuming budget controls on units less than or equal to 25 MWe at RACT levels without a cutoff level. Others supported EPA's proposal of assuming no additional controls on these sources. Some comments suggested exempting medium-sized non-EGU sources.

Many commenters supported the general 1 ton per day exemption contained in the NPR and SNPR. However, a few comments suggested a more stringent cutoff level of 50–100 tons per year, similar to definitions of ''major source'' in the CAA. One commenter recommended a less stringent level of 5 tons per day cutoff level.

A few comments suggest using tons per day as the primary criterion to define large- and medium-sized non-EGU sources, rather than boiler capacity. This approach would exempt, for example, industrial boilers that exceed the 250 mmBtu capacity, but which emit less than one ton per day on average. The EPA's proposed approach considers a source large if heat input capacity data are available and exceed the 250 mmBtu capacity criterion, regardless of its average daily emissions. In support of this approach, commenters stated that industrial operations do not usually operate at or near capacity, while EGUs often do.

A few commenters indicated that the OTAG recommendations for turbines and internal combustion engines (in terms of horsepower cutoff levels) be used. OTAG had recommended cutoff levels of 4,000 horsepower for stationary internal combustion engines and 10,000 horsepower for gas turbines.

Response: For reasons described below and in the NPR (62 FR 60354), EPA believes that the cutoff levels of 250 mmBtu/hr and 1 ton per day for large non-EGU point sources are appropriate. The EPA selected 250 mmBtu/hr and 1 ton per day primarily because this is approximately equivalent to the 25 MWe cutoff used for the EGU sector. Emission decreases from sources smaller than the heat input capacity cutoff level, and that emit less than 1 ton of NO_X per ozone season day, are not assumed as part of the budget calculation; these sources are included in the budget at baseline levels.

The EPA believes that the 1 ton per day exclusion contained in the NPR and SNPR is appropriate and necessary. This level allows today's rulemaking to focus, for the purpose of calculating the budget, on the group of emission sources that contribute the vast majority of emissions, while at the same time avoids assuming emissions reductions from a very large number of smaller sources (as described in the following paragraph). In taking today's first major step towards reducing regional transport of NO_X, EPA does not believe that emission reductions from these small sources need to be assumed. This approach provides more certainty and fewer administrative obstacles while still achieving the desired environmental results. Although other cutoff levels were suggested by commenters, EPA believes that the cutoff levels described above strike the appropriate balance so that reasonable controls may be applied by States to a sufficient but manageable number of sources to efficiently achieve the needed emission reductions.

Most small sources emit less than 100 tons of NO_X per year. Although their total emissions are low, small sources account for about 90 percent of the total number of point sources. Thus, not assuming controls on these sources at the present time would greatly limit administrative complexity and reporting costs. This common-sense approach results in reducing the non-EGU population potentially affected by the ozone transport rule from more than 13,000 sources estimated in the NPR and SNPR to under 1,200.

Although a few comments suggested using tons per day, not capacity (MWe or mmBtu/hr), for setting cutoff levels, EPA chose primarily to use capacity indicators. This approach is consistent with the framework of the emissions trading program. In addition, EPA is concerned that units could have low average emissions during the ozone season but relatively high emissions on some high ozone days. Accordingly, EPA is relying on a capacity approach first and a tons per day approach second (where capacity data is not available or appropriate) to define units for which reductions are assumed in EPA's budget calculations.

As noted in the proposal notices, horsepower data was generally absent from the available emissions inventory data. Thus, the OTAG recommendation could not be used. Because quality assured data are still lacking, EPA used alternative approaches to determine size categories as described above. For the purposes of calculating the State budgets, the following approach is used to determine whether controls should be assumed on a particular source for the purposes of calculating the budget:

1. Use heat input capacity data for each source if the data are in the updated inventory.
2. If heat input capacity data are not available, use the default identification of small and large sources developed by EPA/ Pechan for OTAG and also used to develop the NPR and SNPR budgets for source categories with heat input capacity fields (''default data'').
3. Emission reductions would be assumed if specific source heat input capacity data or default data indicate that a source is greater than 250 mmBtu/hr in the updated inventory.
4. If specific or default heat input capacity data are not available in the updated inventory (or not appropriate for a particular source category), emission reductions would be assumed if the unit's average summer day emissions are greater than one ton per day based on the updated inventory.
5. All others are ''small'' and no emission reductions are assumed.

c. Exemptions for Other Non-EGU Point Sources.

Comments: Several comments described source categories that might be excluded from being assigned assumed emissions decreases for purposes of calculation of the NO_X budgets. In the NPR, EPA assumed a 70 percent reduction from large sources and RACT on medium-sized sources. Some commented that it is not possible to control lime kilns and recovery furnaces or that potential NO_X emissions reductions are very small. One comment noted that recovery units typically emit at a rate of 0.15 lb/mmBtu or less and lime kilns at 0.20 lb/mmBtu or less and suggested establishing an emissions rate floor so that sources emitting less than 0.15 lb/mmBtu (or some other floor) would not need to further control. Other commenters suggested exempting cyclone boilers less than 155 MWe and all aircraft engine test facilities.

Response: The EPA agrees that for purposes of today's rulemaking the State budgets should not reflect assumed reductions in emissions from lime kilns, recovery units and aircraft engine test facilities. The amount of emissions from these source categories is very small relative to other point source categories considered in this rulemaking. Further, there is no experience in applying NO_X control technologies full scale to aircraft engine test cells in the U.S. (EPA–453/ R–94–068, October 1994).

The EPA acknowledges that NO_X controls may be available at costs less than $2,000 per ton for lime kilns, recovery units and aircraft engine test cells. However, these source categories include a relatively small number of sources with a small amount of emissions. The EPA is concerned that assuming controls on these sources for purposes of State budgets would encourage States to attempt to regulate these sources. The EPA believes State regulation could be inefficient because of the relatively high administrative costs of developing regulations for these few source categories (particularly for aircraft engine test cells because no regulations have been developed for this source category).

Similarly, EPA determined for each of the following non-EGU point source categories that the amount of emissions are small relative to the total non-EGU point source emissions and, thus, State regulation could be inefficient because of the relatively high administrative costs of developing regulations for these few source categories: ammonia, ceramic clay, fiberglass, fluid catalytic cracking, iron & steel, medical waste incinerators, nitric acid, plastics, sand/ gravel, secondary aluminum, space heaters, and miscellaneous fuel use operations. Further, for many of these categories the number of sources is small and/or control technology information is limited (e.g., where an Alternative Control Techniques document does not exist for that category). The EPA believes that it would be an inefficient approach to suggest that States consider adopting emissions reduction regulations for each of these categories. Therefore, EPA did not calculate emissions reductions from these source categories for purposes of calculating the budget.

At this stage in the process to reduce regional transport, EPA considers it most efficient to focus State and administrative resources on the source categories with greater amounts of emissions. While States may choose to control any mix of sources in response to the SIP call, EPA is not, in today's rulemaking, assuming reductions from these source categories as part of the budget reduction calculation and does not believe it is necessary for States to do so.

It should be noted that EPA is generally treating the non-EGU boilers/ turbines in the same manner as the EGUs to enable States that opt into a trading program to develop a simple and effective trading program. Thus, the size cutoffs discussed earlier in this section are identical. Further, the regulatory definition of a unit has been revised to make it clear that only fossil-fuel fired boilers and turbines are affected; this is discussed in detail in the trading program section later in today's notice. In addition, it should be noted that EPA is not excluding reductions from cyclone boilers, whether EGU or non-EGU, between 25–155 MWe from the calculation of the State budgets in this rulemaking. Such sources can be large emitters of NO_X and EPA expects the control costs will be less than $2000/ton on average through participation in the emissions trading program.

d. Sources Without Adequate Control Information.

Comments: As described in the SNPR, there are many sources in the emissions inventory which lack information EPA would need to determine potentially applicable control techniques. The SNPR proposed to leave these sources in the budget without assigning any emissions reductions. The EPA received comments that generally supported the SNPR approach not to assign emissions reductions to the diverse group of sources where the Agency lacked sufficient information to identify potential control techniques (63 FR 25909).

Response: This group of sources is diverse and does not fit within the categories set out by EPA, but total emissions are low for this group. The EPA believes that the effort needed to collect adequate information concerning controls for those sources (about 6,000 small and 260 medium or large) would be time consuming, the quality of the information may be uncertain, and it would potentially affect only a small amount of NO_X emissions. Therefore, for purposes of today's action, EPA continues not to assume decreases in emissions for these sources for purposes of calculation of the State budgets, but to keep them in the budgets at baseline levels. In the future, as more information becomes available, and if additional NO_X control is needed to further reduce ozone transport, further consideration of these sources may be necessary. Of course, States with adequate information may choose to control these sources to meet their budgets.

e. Case-By-Case Analysis of Control Measures.

Comments: Some commenters suggested that EPA simply assume reasonably available control technology (RACT) for medium and, in some comments, large sources in all upwind States on a case-by-case basis and assure that marginally stringent source-specific reduction levels are rejected. Many commenters stated that RACT default levels used by EPA were not sufficiently accurate and that case-by-case analysis was needed because every industrial source is different. Other comments generally stated that control level decisions should only be made on a case-by-case basis because each affected unit may have unique features that alter its cost-effectiveness.

Response: In the final budget calculation procedure EPA does not calculate RACT requirements for medium-sized sources. The assumption of RACT or other controls on industrial boilers and turbines between 100–250 mmBtu/hr would have been inconsistent with EPA's approach for utility boilers and turbines, which exempts units less than or equal to 250 mmBtu/hr. To be consistent with the way EPA treats EGUs and because data is often lacking for the smaller size sources, EPA redefined ''affected'' non-EGU units to primarily include those greater than 250 mmBtu. In cases where heat input data are not available, affected non-EGU units are those greater than 1 ton per day; this level is also consistent with the EGU cutoff because it is approximately equivalent to the 250 mmBtu level. Consistency with the EGU approach is important because it provides equity, especially among the smaller boilers and turbines and simplifies the model trading program. Therefore, the final rule does not calculate budget reductions for the medium size non-EGUs.

For the above reasons and as described below, EPA has examined the non-EGU sources on a category-by-category basis and determined appropriate control level assumptions for the large units. There are several reasons why EPA did not choose to calculate the budget by examining sources on a case-by-case basis. First, such an approach would be inefficient since all large sources would need to be examined, rather than some source categories being eliminated due to category specific cost-effectiveness limitations or amount of emissions. Second, it would be very difficult for the States to complete a case-by-case analysis of their large sources, develop rules, and respond to the SIP call within the 12 month time frame (or the statutory maximum 18 months). States needed much more time to respond to a similar requirement, the 1990 CAA NO_X RACT program. The CAA allowed a 2-year period before the NO_X RACT rules were due from the States; however, few States met this time frame and several adopted generic RACT rules which, in practice, resulted in much longer time frames before the case-by-case RACT analyses were completed and State rules adopted. Third, the option of participating in a trading program should mitigate cost impacts on some sources that may have unique configurations or other constraints. Fourth, EPA has often issued standards on a category-wide basis (e.g., New Source Performance Standards) which have proved workable even though some individual units have higher costs than the average. Fifth, the results of such case-by-case analyses may not be perceived to be as equitable as the categorical approach because the control levels resulting from the case-by-case approach are likely to vary from source-to-source and State-to-State. Finally, the category-by-category approach selected by EPA is preferred because it will achieve air quality benefits sooner than the case-by-case approach.

f. Cost-Effectiveness.

Comments: The EPA received numerous comments on cost-effectiveness. Those comments related to uniform control levels or cost per air quality improvement are addressed elsewhere in this notice. Some comments supported EPA's proposed $2,000 per ton approach. Some commented that EPA should use incremental costs, which are the costs and reductions associated with obtaining further control from a unit that already has some level of controls installed. Several commenters suggested using marginal costs, defined as the cost of the last ton of NO_X removed by a control strategy. Many stated that the costs for non-EGUs should be no greater than for utilities on a $/ton basis. One commenter noted that non-EGU costs will be considerably lower than EPA estimates. One comment suggested that EPA assume no further controls if the source has BACT, LAER, MACT or RACT already in place. One comment supported a command-and-control approach instead of the least cost for the non-EGUs, and asserted that controlling 13,000 sources through this rulemaking may not be feasible. Several commenters suggested that CEMS costs for non-utilities should be included in the cost-effectiveness determinations and that alternative monitoring methodologies should be considered.

Response: The EPA believes that the approach of average cost-effectiveness described in the proposal notices is appropriate for this rulemaking. In establishing the upper limit of the cost-per-ton range that EPA considers highly cost-effective for this rulemaking, EPA relied on average cost-effectiveness values estimated for recently proposed or promulgated rulemakings. The marginal cost-effectiveness for the level of control decided upon in the other programs and rulemakings was not always estimated or readily available. The EPA's latest assessment of cost-effectiveness does account for the level of existing or planned control in the baseline case. Therefore, when EPA refers to average cost-effectiveness it is the average incremental cost between the base and the more stringent level of control.

For the non-EGU point sources, in the NPR and SNPR EPA had aggregated the non-EGUs as one group, which meant that a few source categories with relatively low costs and high percentage emissions decreases dominated overall average cost-effectiveness. For today's final action, EPA revised its approach and analyzed individual source categories to determine if control techniques are available at average costs less than $2,000 per ton. Further, EPA included in this cost-effectiveness approach the costs related to CEMS, because this is a new and potentially high cost to some of the non-EGU source categories. As described in the RIA that supports this final rulemaking, EPA's analysis determined that the following non-EGU source category groupings could achieve substantial emissions decreases at average costs less than $2,000 per ton: industrial boilers and turbines, stationary internal combustion engines, and cement manufacturing. As further described in the RIA, controls for sources grouped in the following categories exceed $2,000 per ton: glass manufacturing, process heaters, and commercial and industrial incinerators.

The EPA believes that, over time, costs for non-EGU point sources will be lower than current EPA estimates; however, the changes cannot be quantified at this time. As discussed below, EPA agrees that one source category that has a NO_X standard set through the MACT process should not be assumed to implement further controls.

g. Industrial Boiler Control Costs.

Comments: Several comments were submitted indicating that industrial boiler costs are generally higher than utility boiler costs. The comments cited factors of load variability, smaller size/economies of scale, firing of multiple fuels, and the ability to finance new controls and pass on costs. Some comments stated that most industrial boilers are one-seventh the size of utilities and, thus, EPA should recognize that the costs of controls would generally be higher due to economies of scale.

Response: The EPA agrees that industrial boiler sources are generally smaller than utility boiler sources; however, some individual industrial sources are larger than some utility sources. The EPA agrees that costs, on average, to the industrial sector are expected to be somewhat greater than that expected by the utilities due, in part, to economies of scale and the need for CEMS (which are already in place at utilities). Primarily due to the costs related to continuous emissions monitoring systems, EPA's reanalysis of cost-effectiveness for industrial boilers resulted in a control level of 60 percent, which is less stringent on average than that for utilities.

h. Cement Manufacturing.

Comments: In the NPR, EPA proposed a 70 percent control assumption on large sources and RACT on medium sources, including cement plants. Some commenters suggested that cement manufacturing should be excluded because in the SIP Call area, there are only a few cement plants and they have low emissions. Several commenters noted that many cement plants had already implemented NO_X RACT controls. Some comments disagreed with the costs and controls contained in EPA's Alternative Control Techniques document (EPA–453/R–94–004, March 1994) and added that EPA should not assume the same controls for different types of cement plants. Several commenters stated that 70 percent control is not feasible and SCR costs would be greater than $4,500 per ton, but that 20–30 percent control is possible. One commenter stated that the SIP call would provide a major competitive advantage to plants outside the region, and that multi-plant companies may shut down facilities inside the SIP call region and increase output at plants outside.

Response: Over 50 cement manufacturing units together emit more than twenty percent of emissions from large point sources not in the trading program (about 40,000 tons per season). The EPA believes that the emissions from this one industry are sufficiently high that it is appropriate to examine the availability of cost-effective controls.

The cost and control estimates in the Alternative Control Techniques (ACT) document were peer reviewed and, as such, are considered by EPA as the best data available. Consistent with the ACT document for this industry, EPA generally agrees with the commenters that a 70 percent control level would exceed the $2,000 per ton level used as EPA's cost-effectiveness framework. But, with the evidence cited in the cement ACT document and in some comments, EPA believes that a 30 percent reduction from uncontrolled levels would be within the cost-effectiveness range for reducing emissions at all types of cement manufacturing facilities. Therefore, the budget calculations assume a 30 percent control level for this source category. The EPA does not anticipate that, if States were to choose to apply a 30 percent control level to cement plants, this would be a major competitive disadvantage for plants located in the SIP call area because many cement plants in the region have already successfully implemented such controls in State RACT programs.

i. Stationary Internal Combustion Engines.

Comments: One comment suggested EPA set RACT levels at 25 percent for this category.

Response: As noted above, EPA is not using a RACT approach in the final rulemaking, but has examined each non-EGU point source category separately to determine the maximum available emissions reductions from controls that would cost less than $2,000 per ton on average. As described in the RIA, this process of looking at source categories individually resulted in EPA changing the control level assumption for this category from 70 percent in the NPR to 90 percent control in today's final rule. As described elsewhere in this notice, EPA also changed the control level assumptions for other source categories through this more detailed approach.

For this source category, EPA determined based on the relevant ACT document, that post-combustion controls are available that would achieve a 90 percent reduction from uncontrolled levels at costs well below $2,000 per ton. (EPA–453/R–93–032, 1993.) Therefore, the budget calculations include a 90 percent decrease for this source category from uncontrolled levels.

For spark ignited rich-burn engines, non-selective catalytic reduction (NSCR) provides the greatest NO_x reduction of all technologies considered in the ACT document and is capable of providing a 90 to 98 percent reduction in NO_X emissions. The control technique for spark ignited lean burn, diesel, and dual fuel engines is selective catalytic reduction (SCR). The SCR provides the greatest NO_X reduction of all technologies considered in the ACT document for these engines and is capable of providing a 90 percent reduction in NO_X emissions.

j. Industrial Boilers and Turbines.

Comments: Several commenters indicated that boilers using SNCR may achieve 40–60 percent reduction, but not 70 percent. Other comments supported the 70 percent control level proposed.

Response: The EPA examined the category of industrial boilers and turbines to determine the largest emissions reductions that would result from controls costing less than $2,000 per ton on average, including costs related to CEM systems. As described in the RIA, for this source category, EPA determined that controls, including SCR and SNCR, are available that would achieve a 60 percent reduction from uncontrolled levels at costs less than $2,000 per ton on average. For those sources that participate in the trading program, EPA believes that the costs would be further reduced. Therefore, the budget calculations include a 60 percent reduction for this source category from uncontrolled levels.

k. Municipal Waste Combustors (MWCs).

Comments: Several comments suggested that State budgets should not reflect emissions decreases for MWCs beyond those already required by the MACT rules.

Response: The NPR did not assume reductions for MWCs in the calculation of the budgets. However, since MACT reductions are required, and will be achieved well before 2007, those reductions should be accounted for in the 2007 baseline emissions inventory. The EPA agrees that additional emissions decreases beyond MACT levels are not warranted for this source category at this time because they would exceed the $2,000 per ton framework for highly cost-effective controls. Therefore, EPA has incorporated the NO_X emissions decreases due to the MACT requirements into the 2007 baseline levels and not assume any further reductions.

D. Highway Mobile Sources

Background: For the NPR and SNPR, highway vehicle emissions were projected to 2007 from a base year of 1990. The NPR used the 1990 OTAG inventory as its baseline. The 1990 OTAG inventory was based on actual 1990 vehicle-miles-traveled (VMT) levels for each State, based on State submittals to OTAG where available, or on historical VMT data obtained from the Highway Performance Monitoring System (HPMS) if State data were not available. The EPA proposed to switch to historical 1995 VMT levels from the HPMS; States were encouraged to submit their own 1995 VMT estimates where those estimates differed from HPMS.

In today's notice, EPA has implemented the changes it proposed in the NPR in calculating baseline and projected future NO_X emissions from highway vehicles. A 1995 baseline is used for today's notice in place of the 1990 baseline used in the NPR. The HPMS data were used to estimate States' 1995 VMT by vehicle category, except in those cases where EPA accepted revisions per the comments. These VMT estimates reflect the growth in overall VMT from 1990 to 1995, as well as the increase in light truck and sport-utility vehicle use relative to light-duty vehicle use. The 1995 NO_X emissions inventories also reflect the type and extent of inspection and maintenance programs in effect as of that year and the extent of the Federal reformulated gasoline program. The EPA is continuing to use the growth factors developed by OTAG for the purpose of projecting VMT growth between 1995 and 2007. These growth factors were revised with appropriately explained and documented growth estimates submitted during the comment period for the NPR.

The 2007 highway vehicle budget components presented in today's notice are based on EPA's MOBILE5a emission inventory model with corrected default inputs, which represents the most current EPA modeling guidance to States when developing their SIPs.[60]

1. Base Inventory

Comment: The EPA received a number of comments on baseline highway vehicle emission inventories. Most of these commenters proposed changes to baseline VMT estimates or to control factors related to highway vehicle emissions.

Response: In the NPR and SNPR, EPA asked commenters to provide sufficiently detailed information to permit revision to county-level emission inventories, in order to allow airshed modeling to be performed using the revised inventories. A number of proposed VMT revisions submitted by commenters were not sufficiently detailed to permit county-level inventory revisions and therefore these revisions were rejected. Other commenters provided sufficiently detailed data, which were incorporated into the base year VMT inventory, with two exceptions. Two States submitted 1995 VMT estimates that were inconsistent with EPA and U.S. Department of Transportation information on the relative contribution of light-duty trucks to total VMT. The EPA chose to use the HPMS default data for these two States.

Comment: One commenter asked the EPA to use VMT from the 1996 Periodic Emissions Inventory (PEI) or 1996 National Emissions Trends (NET), rather than 1995 Highway Performance Modeling System (HPMS) data when calculating baseline inventories. Several other commenters supported EPA's use of 1995 HPMS data to calculate baseline VMT inventories.

Response: Guidance on how to construct the 1996 PEI was not released until July 1998 and State PEI submittals are not expected until 1999. The EPA has determined for this reason that the 1996 PEI is not suitable for calculating the baseline VMT inventory. The EPA considered using 1996 NET VMT data in its base inventories, but those data were based on estimated 1995 HPMS inputs. The EPA has chosen to use the actual 1995 HPMS data rather than estimates in order to reduce the uncertainties associated with estimating baseline and 2007 emission inventories.

Comment: One commenter suggested using a multi-year VMT activity average to establish the highway emission baselines to smooth out abnormal patterns, instead of relying solely on 1995 activity.

Response: The EPA proposed using 1995 VMT in order to shorten the time period over which VMT growth would have to be projected. The EPA is not aware of any evidence that suggests that 1995 was an abnormal year in terms of VMT activity. Furthermore, States did not submit multi-year VMT averages in response to the EPA's invitation to submit their own VMT data. If the EPA were to construct multi-year averages, it is not clear what time frame would be appropriate. The EPA believes that the uncertainty related to having to project VMT growth estimates over a longer time period is at least as great as the uncertainty related to the representativeness of 1995 VMT. For these reasons, EPA has chosen to use 1995 VMT for base year and projection year inventories.

Comment: A number of commenters raised various issues about the use of the MOBILE5 emission factor model for this analysis. Most of these comments focused on specific assumptions or estimates incorporated in MOBILE5 which may need to be modified or updated to account for new information.

Response: The EPA is currently developing an updated emission factor model called MOBILE6. When final, this model will supersede the MOBILE5 model used by the EPA to develop baseline and 2007 emission inventories and States' highway vehicle budget components. The concerns raised by commenters are being evaluated as part of the MOBILE6 development process. At the present time, however, MOBILE5 remains EPA's official emission factor model. The EPA currently is not able to determine whether the highway vehicle emission modeling concerns raised by commenters are valid or whether the changes they suggest would raise or lower emission estimates; EPA is also not able to quantify the effects of commenters' concerns using its current emission models. Some of the changes EPA expects to make in its next official emission factor model, such as the effects of aggressive driving and air conditioner use, are likely to raise emission estimates; others, such as less-rapid deterioration of emissions performance than previously forecast, are likely to lower emission estimates. Because the overall effect of these and other changes cannot yet be determined, the EPA has chosen to continue using its current official emission model in today's action.

As discussed in Section III.F.5, the budgets presented in today's action serve as a tool for projecting in advance whether States have adopted measures that would produce the required amount of emissions reductions, as indicated by the initial demonstration submitted in September 1999. The budgets are also a means for determining from 2003 to 2007 whether States are fully implementing those measures. Thus, the budgets are an accounting mechanism for ensuring that the upwind States have adopted and implemented control measures that prohibit the significant amounts of NO_X emissions targeted by section 110(a)(2)(D)(i)(I). Although EPA's

[60] Both MOBILE5a and MOBILE5b are official EPA models. States can use either model in their SIPs, provided they use the corrected default inputs with MOBILE5a. For the control programs evaluated in today's action, MOBILE5a with corrected default inputs gives the same emission estimates as MOBILE5b. Because both models are considered valid by EPA and give the same emission estimates, the EPA has determined that the choice of which model to use in calculating highway vehicle emission budget components is a matter of convenience. The EPA has chosen to retain the use of MOBILE5a for today's action in order to maintain consistency with the OTAG process, in which MOBILE5a with corrected default inputs was used to construct its highway vehicle emission inventories and to calculate the effectiveness of highway vehicle emission control options.

projections of emissions from highway vehicles will change as the Agency improves its emission models, these changes will not in and of themselves require changes in the actions States undertake to reduce ozone transport under today's action.

2. Growth

Comments: The EPA received numerous comments concerning its projection of States' 2007 highway vehicle budget components. In addition to the changes in baseline VMT discussed previously in Section III.D.1 of this notice, the EPA received from a number of States proposed revisions to VMT growth estimates and the effectiveness of emission control programs.

Response: In today's action, EPA has implemented the following changes it proposed in the NPR in calculating States' 2007 highway vehicle budget components. The EPA has used State projections of VMT growth from 1995 through 2007 for States that submitted appropriately explained projections of VMT growth from 1995 to 2007. For other States, EPA projected 2007 VMT levels from the 1995 baseline VMT levels using the OTAG projected growth rates.

As proposed in the NPR, neither the highway vehicle budget components nor the overall NO_X budgets promulgated in today's action alter the existing conformity process or existing SIPs' motor vehicle emissions budgets under the conformity rule. The EPA has determined that Federal agencies or Metropolitan Planning Organizations (MPOs) operating in States subject to today's action do not have to demonstrate conformity to the SIP Call budgets or the highway vehicle budget component levels used to calculate the budgets. However, areas will be required to conform to the motor vehicle emissions budgets contained in the attainment SIPs for the new eight-hour standard. For their attainment SIPs for transitional ozone nonattainment areas, States might seek to rely on the modeling performed for the SIPs submitted in response to today's action. To the extent that this occurs, the VMT projections and motor vehicle emissions inventories associated with today's action could have a role in the conformity process, beginning when transitional areas are designated and classified in 2000.

3. Budget Calculation

Background: The EPA proposed highway budget components based on projected highway vehicle emissions in 2007 from a base year of 1990, assuming implementation of CAA measures, such as inspection and maintenance programs and reformulated fuels, measures already implemented federally, and those additional measures expected to be implemented federally by 2007. The additional Federal measures included the National Low Emission Vehicle Standards and the 2004 Heavy-Duty Engine Standards. The emission effects of revisions to the Federal Emissions Test Procedure, which had also been promulgated in final form, were not reflected in the projected 2007 emissions presented in the proposal because neither the emissions that this measure is designed to control nor the reductions in those emissions expected from the test procedure revisions had been incorporated in the projected 2007 emission estimates or in peer- and stakeholder-reviewed EPA emission models. The proposal also did not incorporate any benefits from Tier 2 light-duty vehicle standards since the EPA had not yet proposed or promulgated regulations concerning the level and implementation schedule for Tier 2 standards. Seasonal emissions were calculated by estimating emissions for a specific weekday, Saturday and Sunday during the ozone season and multiplying by the number of days of each type in the ozone season. These estimates were based on temperatures and temperature ranges recorded for actual ozone episodes. In the NPR, EPA proposed to change this approach to substitute monthly average temperatures and temperature ranges for ozone episode-specific temperatures when constructing the 2007 budgets. The highway vehicle budget components presented in today's notice reflects this change.

Comment: A number of commenters suggested that the EPA change its assumptions regarding emission control programs from those used in the NPR. One commenter claimed that the NPR did not include a number of cost-effective highway and nonroad mobile source NO_X reduction programs in its budget calculations. Other commenters suggested that the EPA focus more on expanding the RFG and I/M programs, adopting gasoline sulfur controls, implementing a reformulated diesel fuel program, or implementing the Tier 2 program. Contrary to these positions, a number of commenters agreed with the EPA's decision not to assume any expansion of the RFG or I/M programs, while still other commenters argued that the EPA should not include the emission effects of gasoline sulfur controls or reformulated diesel fuel in its calculation of State NO_X budgets. One commenter suggested that the EPA change its NLEV phase-in assumptions to match the final NLEV agreement. One commenter asked EPA to include the effect of the recent Revised Federal Test Procedure rule, which is aimed at reducing excess emissions from aggressive driving or air-conditioner use, in its budget calculation.

Response: Both the NPR and today's action include those mobile source reductions which EPA has determined or proposed to determine are technologically feasible, highly cost-effective, and appropriate to implement on a national basis, and which have been promulgated in final form or are expected to be promulgated in final form before States are required to submit revised SIPs. The highway vehicle budget components include the emission reductions resulting from implementation of the NLEV program, including the phase-in schedule agreed to by the States, automobile manufacturers, and EPA. The highway budget components do not include the effect of Tier 2 light-duty vehicle and truck standards and any associated fuel standards since these standards have not yet been proposed.

The extent of the RFG and I/M programs was not assumed to change beyond that assumed for the NPR, except for those States who were able to demonstrate that the NPR's modeling assumptions did not conform to the State's SIP and did not reflect CAA requirements. As discussed elsewhere in today's notice and in the NPR, the NO_X reductions alone from these measures do not appear to be highly cost effective in all of the areas that would be subject to reduced budgets. Because these measures offer additional benefits beyond NO_X reductions, specific local areas may determine that these measures are appropriate and cost effective given their full range of benefits.

The baseline and budget calculations include neither the increased emissions from aggressive driving or air conditioner use, nor the reductions in those emissions resulting from the Revised Federal Test Procedure rule. These emission effects are not reflected in EPA's MOBILE5a model; they are being evaluated for inclusion in MOBILE6. While the EPA has developed a modified version of its MOBILE5 model to estimate these effects for its Tier 2 study, this modified model has not been used in any regulatory actions and is still subject to revision as part of EPA's model development process. As discussed above and in Section III.F.5. below, any changes by EPA in its emission models will not in and of themselves alter the emission reductions States must achieve to comply with the requirements of today's action.

Comment: One commenter suggested that the EPA not split VMT using weekend and weekday travel fractions when calculating monthly and seasonal total VMT. Another State commenter proposed an alternative method for calculating monthly and seasonal VMT from average daily VMT which did not rely on the EPA weekend/weekday travel fractions, but instead used monthly travel fractions specific to that State. Other commenters supported the weekend/weekday inventory modeling approach proposed by the EPA.

Response: The EPA and other organizations have amassed considerable evidence that weekend and weekday travel patterns differ significantly. The OTAG Final Report requested day-specific inventories for developing day-of-the-week activity levels used in emission inventory development and episode-specific modeling. Given this requirement, EPA has determined that the approach outlined in the NPR is appropriate and reasonable. The alternative method using State-specific monthly travel fractions as proposed by one State is a reasonable alternative. However, because EPA does not have the necessary information to apply this method to all other States, EPA did not incorporate this method in its analysis.

a. I/M Program Coverage.

Comment: One commenter urged the EPA to expand I/M programs to cover all urbanized areas with populations above 500,000 as recommended by OTAG. Other commenters also requested that EPA expand the I/M program or require specific States to adopt specific types of I/M programs. By contrast, other commenters supported the I/M approach taken by the EPA in the NPR.

Response: The OTAG recommended that States consider expanding I/M programs to cover all urbanized areas with populations above 500,000. The EPA has considered this recommendation but does not believe it to be appropriate to assume broader I/M implementation in calculating State budgets for the reasons outlined in the NPR (62 FR 60355). The State budgets promulgated in today's action reflect full implementation of I/M as required by the CAA and State SIPs.

b. Emissions Cap.

Comment: One commenter suggested that the EPA consider capping mobile source emissions, arguing that the proposed rule would place an undue burden on stationary sources.

Response: The State NO_X budgets promulgated in today's action include the projected emission benefits of those NO_X controls that the EPA has determined are technologically feasible and highly cost effective, as well as additional controls whose implementation is not dependent on this rule. While the EPA's analysis indicates that certain categories of stationary sources offer the potential for large, highly cost-effective NO_X emission reductions, the State NO_X budgets also reflect the emission effects of a number of mobile source controls (See Table IV–2). The EPA believes that it has applied its criteria for determining which controls to assume in State NO_X budgets equitably to both mobile and stationary sources. In contrast to EGUs and large non-EGUs, EPA has not concluded that a mass cap (which would effectively require offsets for VMT growth) is highly cost effective. For these reasons, EPA does not believe that today's action places an undue burden on any emission sector and does not believe that a separate cap on mobile source emissions is necessary.

c. Tier 2 Standards.

Comment: One commenter requested that EPA include the effects of Tier 2 light-duty vehicle standards when calculating State budgets if the NLEV program fails. Another commenter suggested that States not be permitted to adjust their budgets in case the NLEV program fails.

Response: This issue is not yet ''ripe'' because NLEV is currently being implemented and there are no signs that the program will fail. The EPA will consider whether to adjust State budgets if automakers representing a significant portion of new vehicle sales withdraw from the NLEV program, as discussed in Section III.F.5.

d. Low Sulfur Fuel.

Comment: One commenter stated that the EPA disregarded OTAG's call for reducing sulfur levels in fuel, which would have the effect of reducing NO_X emissions.

Response: The EPA's proposed rule and other actions match the OTAG recommendations on fuels, contrary to the commenter's suggestion. The OTAG gasoline recommendation stated, ''The USEPA should adopt and implement by rule an appropriate sulfur standard to further reduce emissions and assist the vehicle technology/fuel system [to] achieve maximum long term performance.'' It did not request that EPA implement a specific sulfur reduction proposal. The EPA is evaluating the costs and benefits of reducing gasoline sulfur levels as part of its proposed rulemaking to implement Tier 2 light-duty vehicle and truck standards. The EPA is also evaluating the relationship between diesel fuel standards and the emission standards as part of (i) its 1999 technology review for its 2004 highway heavy-duty diesel engine standards and (ii) its 2001 technology review for the Tier 3 and Tier 2 nonroad diesel engine standards. Until these evaluations are complete, EPA believes it is premature to assume any changes in fuel properties when calculating States' highway vehicle budget components.

e. Conformity.

Comment: One commenter recommended that NO_X transportation conformity waivers should lapse in the wake of today's action.

Response: Conformity waivers were granted on an area-by-area basis, given the facts of the situation in each local area. Any withdrawal should be based on similar local analysis, or upon submittal of a valid attainment plan. Today's action is not based on this kind of local analysis. Thus, there is no basis for any withdrawal of existing NO_X transportation conformity waivers. Furthermore, any such withdrawal would not alter the Statewide NO_X budgets set forth in today's action. For these reasons, the EPA has concluded that today's action does not alter existing conformity requirements, including any NO_X conformity waivers.

Comment: One commenter expressed concern that if current conformity budgets do not incorporate the same control assumptions as the States' budgets submitted in response to today's rulemaking, the growth in areas currently subject to conformity budgets could threaten the ability of States to meet the SIP call budgets. The commenter continued that failure to tie conformity budgets to transport budgets would allow these areas to grow to pre-SIP call control budget levels that could cause an exceedance of the Statewide budget. The commenter also stated that to address local ozone problems, transportation conformity plans should reflect the mobile source controls assumed in the SIP call.

Response: Conformity budgets cannot be tied directly to the SIP Call budgets because the latter are statewide and the former are nonattainment-area-specific. The Statewide NO_X budgets will be enforced as described in today's action, regardless of the conformity budgets in specific areas within the affected States. These budgets should reflect the actual level of motor vehicle emissions which States expect to occur.

As noted elsewhere in this section, conformity budgets will reflect the mobile source controls assumed in the SIP Call budgets to the extent that the attainment SIP ultimately relies upon those controls. Today's action does not change the rules governing generation and use of emission reduction credits to offset further growth in the transportation sector as part of a local area's conformity demonstration.

E. Stationary Area and Nonroad Mobile Sources

Background: The EPA developed the NO_X SIP call emissions inventory for area and nonroad mobile sources based on data sets originating with the OTAG 1990 base year inventory. These base year inventories were prepared with 1990 State ozone SIP emission inventories supplemented with either State inventory data, if available, or EPA's National Emission Trends (NET) data if State data were not available. The OTAG 1990 nonroad emission inventories were based primarily on estimates of actual 1990 nonroad activity levels found in the October 1995 edition of EPA's annual report, ''National Air Pollutant Emission Trends.'' In the NPR, EPA proposed switching to EPA's 1997 ''Trends'' estimate of 1995 nonroad activity levels.

For the SNPR, area and nonroad mobile source inventory data for 1990 were then grown to 1995 using Bureau of Economic Analysis (BEA) historical growth estimates of industrial earnings at the State 2-digit Standard Industrial Classification (SIC) level. Because BEA data are historical documentation of industry earnings, EPA considered these to be among the best available indicators of growth between 1990 and 1995 (63 FR 25915). Once the common base year of 1995 was established for these source categories, BEA growth assumptions utilized by OTAG were used to estimate the 2007 base case inventory.

1. Base Inventory

Comment: The EPA received several comments on baseline area and nonroad mobile source emission inventories. Several commenters submitted estimates of their 1990 nonroad activity levels that differed from NPR estimates. One commenter provided statewide 2007 base year emissions estimates for numerous area source categories, while others provided similar information for 1990 or 1995 emission estimates. Many commenters expressed concern with existing area source inventory estimates and provided revised county-level area source inventories. One commenter suggested using a multi-year activity average to establish the nonroad emission baseline, arguing that a multi-year average would provide a more representative baseline than would a single year's data alone.

Response: In the NPR and SNPR, EPA asked commenters to provide sufficiently detailed information to permit revision to county-level emission inventories, in order to allow airshed modeling to be performed using the revised inventories. Some proposed area and nonroad inventory revisions submitted by commenters were State-wide revisions and did not contain sufficient detail to permit the EPA to revise county-level nonroad emission inventories. Because the EPA could not use these submittals to revise the county-level inventories used as inputs to its air quality modeling analyses, these submittals were not accepted. Other commenters did provide sufficiently detailed data, and EPA revised the appropriate emission inventories to reflect the commenters' estimates. These revised inventories were then grown to 1995 using BEA-derived growth factors, as described above.

Although EPA proposed in the NPR to switch to a 1995 inventory in calculating baseline NO_X emissions from nonroad mobile sources, EPA has chosen not to do so in today's action. Using the 1995 inventory presented in the ''Trends'' report as the baseline for today's action would have required the use of geographic allocation methods that have not undergone peer review and have not been made available for public comment by affected interests. The EPA has concluded that the use of these unreviewed methods in today's action would have deprived stakeholders of adequate opportunity to review, understand, and comment on their baseline inventories and the methods used to construct them. Hence, EPA has chosen to retain the 1990 baseline inventories for nonroad mobile sources presented in the NPR for today's action, with the changes made in response to comments.

As discussed above, EPA has chosen to use 1990 nonroad activity level estimates as the basis for its nonroad inventory projections. The EPA is not aware of any evidence that suggests that 1990 was an abnormal year in terms of nonroad activity. Furthermore, States did not submit multi-year nonroad activity averages in response to EPA's invitation to submit their own nonroad activity data. If EPA were to construct multi-year averages, it is not clear what time frame would be appropriate. To reduce the impact of unusual years, EPA would have to take a long-term average. However, doing so would require EPA to use an even earlier year as its base year for nonroad activity and inventory projections. The EPA believes that the uncertainty related to having to project nonroad activity growth estimates over a longer time period is at least as great as the uncertainty related to the representativeness of 1990 nonroad activity.

2. Growth

Comment: Several commenters suggest that the growth factors used to determine 2007 stationary area and nonroad mobile source base year inventories are inaccurate or inconsistent across regions and categories of the inventory. They explained that if growth factors are to be used to estimate future base year emissions, consistent national or region-wide values should be utilized for all categories across all States within the domain. This, they continue, would promote equitable potential progress to all areas and not penalize those that have shown past poor growth rates. Some commenters go on to state that growth rates based on past growth automatically disadvantage States which have suffered from unusually low growth rates. In addition to growth rates, some commenters provided 2007 base year emission estimates either with or without the growth and control information needed to validate their calculation.

Response: As noted above, EPA relied on BEA State-specific historical growth estimates of industrial earnings at the 2-digit SIC level as among the best available indicators of growth for stationary and nonroad area sources. BEA projection factors assume the continuance of past economic relationships. These factors are published every five years and adjusted to account for recent production and growth trends. For this reason, BEA data provide a useful set of regional growth data that EPA recommends for use in preparing emission inventory projections. It is true that BEA projection factors differ among different areas and different source categories because of historical differences in industrial growth among those different areas and source categories. However, in general, these projection factors offer the most reliable indicators of future growth as are available.

In cases where commenters questioned the use of EPA's growth rates but provided no alternative of their own, EPA had little choice but to continue to use the BEA-derived growth rates. Some commenters provided alternative or supporting information for modification of source category or State growth estimates. In those cases where a State or industry may have had more accurate information than the BEA forecast (e.g., planned expansion or population rates), data were verified and validated by the affected States and by EPA, and revisions were made to the factors used for that category.

3. Budget Calculation

Background: The EPA proposed nonroad mobile source budget components based on projected nonroad mobile source emissions in 2007 from a base year of 1990. These projections were developed by estimating the emissions expected in 2007 from all nonroad engines, assuming implementation of those measures incorporated in existing SIPs, measures already implemented federally, and those additional measures expected to be implemented federally. The additional Federal measures include: the Federal Small Engine Standards, Phase II; Federal Marine Engine Standards (for diesel engines of greater than 50 horsepower); Federal Locomotive Standards; and the Nonroad Diesel Engine Standards. In the NPR, EPA used the estimates developed by the OTAG for nonroad mobile source baseline emissions and growth rates.

Comments: The EPA received comments to use a State-specific set of growth rates for nonroad mobile source emissions.

Response: The EPA has used State estimates of 1990 nonroad activity levels and growth rates for 1990 through 2007 received during the comment period to revise its estimates of nonroad NO_X emissions in 2007, where those State estimates were appropriately explained and documented. For other States, the EPA has retained the baseline activity levels and growth rates used in the NPR, which in turn were based on the growth rates developed for OTAG.

F. Other Budget Issues

1. Uniform vs. Regional Controls

Background: In the NPR, EPA bases the State budgets upon assumed application of reasonable, highly cost-effective NO_X control measures. These measures were uniform across the 23 affected jurisdictions. They consisted of 0.15 lbs/MmBtu for the EGU sector; and 70 percent control for large, and RACT for medium-sized, non-EGU point sources.

Comments: A number of commenters opposed calculating budgets based on uniform emissions reductions and cited the fact that OTAG recommended a range of control levels. These commenters offered no specific alternatives, such as varying the assumed control levels by State or by groups of States, or alternative methods for determining different control levels. Numerous comments were received supporting the proposed uniform level of emissions reductions.

Response: The EPA has determined that each of the 23 jurisdictions has sources that emit NO_X in amounts that significantly contribute to downwind nonattainment problems. Moreover, EPA has determined that specified levels of control on certain sources in all of the jurisdictions would be highly cost-effective. This analysis applies with equal force to each of the 23 jurisdictions. It may be that emissions from some States have greater ambient impact on downwind nonattainment areas than emissions from more distant States. Even so, each of the States' NO_X emissions have a sufficient ambient impact downwind to conclude that those amounts are significant contributions and that NO_X emissions from all the upwind jurisdictions collectively contribute significantly to nonattainment downwind. Differentiating the contributions of individual upwind States on multiple downwind nonattainment areas is a highly complex task. The contributions of individual States are likely to vary from downwind area to downwind area, from episode to episode, and from NAAQS to NAAQS. Accordingly, it would be extremely complex to develop a budget for each State that would reflect the different impacts of its sources' emissions on different downwind States.

Among many factors that EPA considered in weighing whether to finalize a uniform control level or regional control levels in calculating States' emission budgets was the concern that different controls in one part of the SIP call area in combination with an interstate emissions trading program may lead to increases in pollution within areas having more restrictive controls. That is, if unrestricted interstate emissions trading were allowed on an one-for-one basis, emissions reductions might be expected to shift away from States assigned more restrictive controls to States which received less restrictive control requirements due to the lower control costs likely to exist in States with less restrictive controls. This may result in emissions above the budget level in areas with more restrictive controls.

There are two alternatives for addressing the problem of shifting emissions. The first is to allow trading only within uniform control regions, but not between regions with NO_X budgets reflecting different levels of control. The advantage to this approach is that it provides a straightforward way of preventing trades of excess emissions into regions with more stringent standards. However, a trading program that covers a smaller market area will provide less flexibility and reduce the possible savings for the affected sources as compared with larger trading programs. The second alternative is to establish a trading ratio for trades between regions, to reflect the differential impact of the emissions on nonattainment. The trading ratio should reflect the relative contribution of emissions to downwind non-attainment problems. The advantage to this approach is that it provides the flexibility for trades between regions when the benefits of such trades are large, while discouraging a shift of excess emissions into regions with more stringent standards. However, none of the comments on the proposal included a justification or description for trading ratios, which would reflect the differential environmental implications and discourage inappropriate shifting of excess emissions.

The ozone problem in the Eastern United States is the result of a large number of different types of sources which affect widely distributed nonattainment areas at different times under changing weather patterns such that a broadly-established control program is necessary. The EPA believes a reasonable strategy is to apply the most cost-effective control strategies uniformly in contributing States in order to eliminate the combined significant contribution from these multiple sources in multiple States.

The EPA analyzed costs and air quality benefits for two regional control level options that were based on a varying level of controls in different parts of the 23 jurisdictions. The analysis did not show that these two regional control alternatives would provide either a significant improvement in air quality or a substantial reduction in cost. An analysis of the costs and benefits of different control options can be found in the docket. On the basis of the analysis, EPA believes an alternative approach with differentiated NO_X budgets and regionally differentiated trading would not yield significant additional air quality benefits or cost savings vis a vis a regionwide trading program based on uniform NO_X budgets.

2. Seasonal vs. Annual Controls

Comments: One commenter suggested that controls should be required for the entire year rather than just during the 5-month ozone season as proposed.

Response: The EPA recognizes that control of nitrogen oxide emissions would likely produce non-ozone benefits, as well as ozone benefits. For example, NO_X control would likely reduce surface water acidification or eutrophication of surface waters. Annual control of NO_X may have a greater impact on winter and spring NO_X emissions, and therefore on acidification and eutrophication, than ozone season (summer) NO_X control to the extent that acidification and eutrophication result from the release of nitrogen compounds from snowpack during snowmelt and rain in the spring. Control of NO_X emissions also reduces fine particulates and regional haze, so that annual control of NO_X emissions would result in greater non-ozone benefits. However, the commenter's suggestion that EPA analyze the costs of, and assume in calculating the budgets, annual NO_X control to address non-ozone problems is outside the scope of this rulemaking proceeding. Here, EPA has proposed a NO_X SIP call to address the failure of certain SIPs to prohibit sources from emitting NO_X in amounts that contribute significantly to nonattainment (or interfere with maintenance of attainment) of the ozone NAAQS during the ozone season.

In analyzing the benefits of ozone season NO_X control under the proposed NO_X SIP call for purposes of the RIA (though not as a basis for the decisions in today's rule), EPA considered both the ozone and non-ozone benefits. Non-ozone benefits include the impact of ozone season NO_X control on acidification and eutrophication. In particular, emission modeling performed by EPA indicates that the SIP Call would reduce wintertime NO_X emissions. This results in part because, once installed to comply with the NO_X SIP call, some NO_X control systems (e.g., low NO_X burners which alter the combustion process and cannot simply be turned off) would reduce emissions throughout the year, even though the NO_X limits would be seasonal. Also see Section IX.

3. Full vs. Partial States

Background: In the NPR, the Agency indicated it was proposing to include entire States rather than exempting portions of States in the development of emissions budgets. The Agency's decision to include full States was based upon three major points: (1) The division of individual States by OTAG was based, in part, on computational limitations in OTAG's modeling analyses; (2) the additional upwind emissions from full, as opposed to partial, States would provide additional benefit to downwind nonattainment areas; and, (3) Statewide emissions budgets create fewer administrative difficulties than a partial-State budget.

Comments: During the two comment periods, 43 comments were received which specifically addressed some or all of the major points outlined above. The underlying theme throughout the comments on this issue was that the States and EPA had undertaken a comprehensive, scientifically credible modeling/analysis study during the OTAG, and that the Agency should follow OTAG's recommendations on this issue (i.e., allow for partial-State emission budgets). Another common theme was that the administrative difficulties outlined by the Agency in the NPR were exaggerated, and that the affected States should be allowed to generate partial-State, as opposed to statewide, emissions budgets, if their State considered it feasible to do so. Comments were received that portions of Alabama, Georgia, Michigan, Missouri, North Carolina, and Wisconsin should be excluded from the SIP Call.

Response: The underlying concepts for responding to these comments are (a) that the atmosphere is constantly in motion and has no limitations at geo-political boundaries, and (b) that the larger the geographic area that is controlled, the greater the downwind benefits. For the States requesting partial-State emissions budgets, there are NO_X emissions throughout these entire States. The EPA did State-specific modeling for each of the affected States, and these additional modeling analyses support the concept of statewide emissions budgets for each of the affected States. Furthermore, it is a reasonable assumption, given the nature of ozone chemistry, that if emissions from part of a State contribute significantly to downwind nonattainment or maintenance problems, emissions from the entire State contribute significantly to downwind nonattainment or maintenance problems. In each of the affected States, there is no peculiar meteorological phenomenon that would indicate that emissions from some portion of that State would not impact downwind nonattainment or maintenance problems. Thus, based on additional EPA modeling analyses and their technical interpretation, EPA is not promulgating partial-State emissions budgets. Since each State has the flexibility to determine which sources to control in order to meet the budget, a State can structure its control strategy to require fewer reductions in certain portions of the State and greater controls in other areas, as long as the significant amounts of emissions are eliminated.

4. NO_X Waivers

Comments: The EPA received several comments supporting the approach outlined in the NPR in which EPA would treat areas that had previously received NO_X waivers under section 182(f) of the CAA in the same manner as other areas in the SIP call. The comments stated that (1) special treatment (i.e., higher budget) for the waiver areas would increase the burden on downwind States; (2) numerous modeling efforts, including OTAG's, have shown that such disbenefits are generally minor and occur on days with low ozone concentrations; (3) disbenefits are small when upwind NO_X reductions are modeled; (4) disbenefits are better addressed at the local level; and (5) States already have the flexibility to deal with NO_X disbenefits, if any, through the budget and trading by meeting the budget through NO_X emission decreases in other areas of the State or acquiring allowances through trading. In addition, some commenters requested EPA to revoke waivers previously granted. Commenters also noted that the localized disbenefits are no less of a problem in the Northeast than in the Midwest.

Numerous comments were also submitted which oppose the approach outlined in the NPR. The comments generally stated that in States with NO_X waiver areas, the NO_X budget should be increased where NO_X decreases lead to ozone increases; otherwise States might seek reductions disproportionately outside the sensitive areas, resulting in cost-effectiveness levels greater than the $2000 per ton framework described in the SIP call proposals. Comments referred to disbenefits in Cincinnati, Louisville and the Chicago/Gary areas. Many commenters suggested that EPA wait for further modeling analyses to be completed and that the zero-out runs are inappropriate for evaluating the NO_X disbenefit issue. Some stated that the NO_X budget might interfere with local attainment and harm local public health. Other comments recommended that EPA consider the impact of additional VOC costs that might be needed to offset local ozone increases.

Response: In today's final rulemaking, EPA is setting NO_X emissions budgets for each of the jurisdictions affected by this action. These budgets are set in the same manner for areas without NO_X waivers as areas with NO_X waivers, except in the case of NO_X waivers granted for I/M programs. Although adverse comments were submitted, none of them provided any modeling analysis or support documentation showing how a State or States with NO_X waiver areas should be assigned a larger budget or proposing a specific alternative approach for assigning those budgets. In contrast, modeling described by EPA in the NPR and SNPR as well as additional modeling conducted by the Agency and some commenters continues to show that the benefits of NO_X emissions decreases greatly outweigh any disbenefits. These findings are discussed in Section IV, and summarized below.

The EPA considered the strengths and limitations in the commenters' modeling analyses in evaluating whether the technical evidence presented in the comments supports the arguments made by the commenters. The EPA's review of the commenters' modeling indicates that in general (a) downwind ozone benefits increase as greater NO_X controls are applied to sources in upwind States, (b) the net benefits of NO_X control at the level of the SIP Call outweigh any local disbenefits, and (c) upwind NO_X reductions tend to mitigate local disbenefits in downwind areas.

One commenter, the Lake Michigan Air Director's Consortium (LADCO), submitted air quality modeling directed toward investigating the disbenefits in nonattainment areas around Lake Michigan due to the NO_X controls in the SIP Call proposal. The commenter's general finding was that the greatest ozone decreases with these NO_X controls occur on high ozone days, while the greatest disbenefits occur on low ozone days. The EPA concurs with this finding, based on a review of the technical information provided by the commenter. Specifically, there were no predicted increases in ozone (i.e., disbenefits) in peak 1-hour ozone on any of the 4 days modeled by LADCO that had daily maximum 1-hour concentrations >=125 ppb in the Base Case. Also, on the 3 low ozone days which had predicted disbenefits, the increases were not large enough to result in a peak value >=125 ppb. Concerning 8-hour concentrations, only 1 of the 9 days with a predicted 8-hour daily maximum concentration >=85 ppb had an increase in peak ozone due to the SIP Call NO_X controls. Also, there was a small disbenefit on the one day modeled which had an 8-hour daily maximum concentration <85 ppb, but the magnitude of the disbenefit on this day was relatively small and did not cause the 8-hour peak value to exceed 85 ppb. Thus, based on this evaluation, EPA generally found that the submitted modeling did not refute the overall conclusions EPA has drawn concerning the impacts of NO_X emissions in the relevant geographic areas.

As described in the NPR, the OTAG process included lengthy discussions on the potential increase in local ozone concentrations in some urban areas that might be associated with a decrease in local NO_X emissions. The OTAG modeling results indicate that urban NO_X emissions decreases produce increases in ozone concentrations locally, but the magnitude, time, and location of these increases generally do not cause or contribute to high ozone concentrations. That is, NO_X reductions can produce localized, transient increases in ozone (mostly due to low-level, urban NO_X reductions) in some areas on some days, but most increases occur on days and in areas where ozone is low. In the SNPR, EPA documented the estimated ozone benefits of the proposed Statewide NO_X budgets based on an air quality modeling analysis. The major findings of that analysis include: Any disbenefits due to the NO_X reductions associated with the budgets are expected to be very limited compared to the extent of the air quality benefits expected from these budgets.

The results of EPA's assessment of the comments and available modeling corroborate and extend the findings presented in the SNPR. Thus, with respect to regional ozone transport and today's final action, EPA believes it is not appropriate to give special treatment to areas with NO_X waivers.

Several nonattainment areas in the 23 jurisdictions were granted waivers from certain NO_X requirements in past rulemaking actions. In the **Federal Register** notices granting the waivers, EPA stated that the continued approval of these waivers is contingent on the results of the final ozone attainment demonstrations and plans (See 61 FR 2428 January 26, 1996, LADCO). The attainment plans will supersede the initial modeling information which was the basis for waivers EPA granted (e.g., the LADCO waiver). The attainment plans were due in April 1998 and were to incorporate the results of the OTAG process. The EPA's rulemaking action to reconsider the initial NO_X waiver may occur simultaneously with rulemaking action on the attainment plans. Therefore, as these new modeling analyses are submitted to EPA, they will be reviewed to determine if the NO_X waiver should be continued, altered, or removed.

As discussed above, EPA has accounted for the continued presence of NO_X waivers for I/M programs in modeling States' NO_X budgets. Historically, EPA gives States considerable latitude in designing their I/M programs. This latitude is granted in recognition of the unique economic and air quality circumstances faced by each State. States have used this latitude to develop a range of I/M program designs. Some States have adopted EPA-recommended enhanced I/M programs; other States have adopted different I/M program designs.

The EPA acknowledges that some of the States granted NO_X waivers may be able to modify their programs to obtain NO_X reductions at minimal cost. However, some of the States which have been granted an I/M NO_X waiver have developed unique I/M program designs in terms of the model years covered, the emission testing equipment used, and possibly the number, location, and design of the testing and repair stations. The cost for these States to modify their I/M programs to obtain NO_X reductions are likely to exceed the level that EPA has determined to be highly cost-effective for the purpose of reducing ozone transport. As a result, the EPA has chosen to not include additional emissions reductions due to I/M NO_X programs when calculating NO_X budgets.

5. Recalculation of Budgets

In the NPR, the EPA made proposals concerning what would happen if additional information becomes available after EPA's final rulemaking action. Examples of such information might include: (a) Source-specific information useful in determining RACT, (b) revised growth or other assumptions, (c) revised models and inventory estimates, (d) unexpectedly low implementation rates for NLEV, and (e) other new federal measures, i.e. Tier 2 controls. In the Recalculation of Budgets Section of the NPR, EPA proposed that if additional data become available after EPA's final rulemaking action, such data could be considered prior to State submittal of revised SIPs. The EPA asked for comments on this approach.

Most of the comments received were in favor of allowing States to adjust their emission budgets based on the most recent available data on emissions and RACT levels. There were several comments that any new calculation methodologies should be applied across all States and be approved at EPA Headquarters, and that all States should use the same methodology.

A few commenters did not agree, however. One said that EPA should not recalculate the budgets upward. Another said there should be no downward ratcheting of budgets. One commenter said that it would be premature to assume that as new information becomes available the budget should be adjusted to reflect this. According to this commenter, it would be more appropriate to perform a complete air quality modeling analysis to determine if an adjustment in States' NO_X budgets is in order.

The divergent views reflected in these comments has convinced EPA that it should clarify the role of the budgets in this rule. In light of that role, as explained below, EPA has decided to allow only a limited opportunity to revise the budgets in the very near term. However, under the approach the Agency is following, the rule would not penalize States for not ultimately achieving the budgets, if the State initially projected compliance using the data set forth in this rule, and the State has fully implemented all of the measures reflected in those initial projections, and the measures are as effective in reducing NO_X emissions as they were projected to be in the State plan.

As explained in the NPR, SNPR, and above, EPA based the budgets on its choice of measures that are highly cost-effective and therefore are the easiest for upwind States to implement to reduce transport. However, EPA sought to structure the rule to give the upwind States a choice of which mix of measures to adopt to achieve the aggregate amount of required NO_X emissions reduction.

To offer the States this choice, EPA employed a multi-step approach leading to a numerical budget for each State. In the first step, EPA projected the mass emissions for EGUs and industrial boilers out to 2007, taking into account measures required under the CAA and projected growth. The result was a base case 2007 subinventory for each of those two categories. Next, EPA projected the 2007 mass emissions for other sectors of the emission inventory (e.g., mobile sources), again taking into account projected growth and measures required under the CAA and existing SIPs, thereby creating a base case 2007 subinventory for each of them as well. The aggregation of all of the base case 2007 subinventories is the complete base case 2007 inventory. The EPA then applied cost-effective control measures to the EGU, industrial boiler and other non-EGU source categories as explained in section III., to determine the amount of the reductions from these categories. The EPA applied control measures to the base case inventory to develop the final budget. Thus, the final budget is the sum of (1) the emissions remaining after application of the cost-effective control measures to the subinventories for the categories for which controls are assumed for purposes of budget calculation and (2) the emissions in the base case 2007 subinventories for the categories for which EPA assumed no controls.

The rule then requires each upwind State to use the same base case 2007 inventory in its 1999 SIP submittal as EPA used in developing the State's budget. In that SIP submittal, the State must show that the measures it has adopted will achieve the same aggregate emissions reductions as the control strategies assumed by EPA in developing the State's budget. More specifically, to demonstrate compliance with the SIP call, a State must adopt and implement control measures that are projected to achieve the aggregate emissions reductions determined by EPA based on the application of highly cost-effective controls to EGUs, industrial boilers and other affected non-EGUs. While a State may choose to achieve those reductions through application of measures other than those used by EPA in calculating required reductions, any measures it adopts must achieve the reductions assumed by EPA in the development of its budgets.

The control measures that the State chooses to require will become the enforceable mechanism under the NO_X SIP call. If a State elects to regulate boilers, turbines or combined cycle units that are greater than 250 mmBtu/hr— regardless of whether they are connected to an electrical generator of any size—or to regulate boilers, turbines and combined cycle units that serve electrical generators greater than 25 Mwe, regardless of the heat input capacity of the unit, the State must provide mass emissions limits or their equivalent (see section VI.A.2) for these sources or source categories. The mass emissions limits may be set on a source-by-source basis or may be set for an entire group of sources allowing trading between the sources. These mass emission limits must assume growth no greater than EPA's calculations. Any growth that occurs in that category would have to be accommodated within the mass emission allocations provided by the State for that category, even if the growth in that category should prove to exceed EPA's projections. This is appropriate because as discussed in the SNPR and Section VI.A.2. of today's preamble, EPA believes that the control approaches, growth assumptions, and monitoring for this group of sources have advanced to the point that complying with, tracking, and enforcing a maximum mass emissions limit is reasonable. Furthermore, based on the analyses in the RIA, EPA believes that mass emission limits remain highly cost-effective for these categories when growth is accommodated within the limits. The EPA modeled the expected growth in capacity and capacity utilization of the source categories listed above based on growth assumptions in the IPM that have been subject to extensive public comment and refinement over a several-year period. On the basis of their growth, assumptions and assumed emissions rates, EPA determined that mass emission limits would remain highly cost-effective when new sources are covered within the limits. EPA projects that even if actual growth for this group of sources exceeds the projected growth by over one-third, mass emission limits would remain highly cost-effective according to the criteria used for this rule.

For other categories, EPA will not require a State to remain within a mass emission allocation. Today's rule does require a State to use the base case 2007 inventory in its budget demonstration. However, the rule does not require States to obtain additional reductions in cases where a State's 2007 emissions exceeds its budget due to higher than expected emissions from source categories other than the categories listed above (certain boilers, turbines, and combined cycle units). These exceedances may be the result of growth that exceeds projections for those source categories. However, if a State elects to control these other source categories to achieve the required reductions in whole or part, the adopted measures must be as effective in reducing NO_X emissions as they were projected to be in the State plan. Any failure by a State to adopt measures adequate to achieve reductions equal to the required amount would be treated as noncompliance with this rule. Any failure by the State to implement these measures by the appropriate date would be considered a failure to implement those measures.

In contrast, the overall budget number itself is not enforceable against the State. The budget serves as a tool for projecting in advance whether a State has adopted measures that would produce the required amount of emissions reductions, as indicated by the initial demonstration submitted in September 1999. The budgets are also a means for determining from 2003 to 2007 whether States are fully implementing those measures. Thus, the budgets are an accounting mechanism for ensuring that the upwind States have adopted and implemented control measures that prohibit the significant amounts of NO_X emissions targeted by section 110(a)(2)(D)(i)(I).

Given that States will not be subject to enforcement actions if emissions in 2007 from uncontrolled sectors exceed the base case 2007 inventory projections, EPA does not intend to revise those projections merely because such new information becomes available over time. Rather, EPA intends to allow commenters an additional opportunity to request revisions to the source-specific data used to establish each State's budget in this SIP call. This opportunity will be made available during the first sixty days of the 12-month period between signature of today's rule and the deadline for submission of the required SIP revisions (i.e., November 23, 1998). Commenters would need to submit any proposed changes in their inventories to the EPA Air and Radiation docket (A–96–56) within that sixty day period. Individuals interested in modifications requested by commenters may review the materials as they are submitted and available in the docket. At the end of this period, EPA will, within sixty days, evaluate the data submitted by commenters and, if it is determined to be technically justified, revise this rule to incorporate it into the State budget determinations. For a comment to be considered, the request for modification must be submitted in electronic format containing, at a minimum, the data elements listed below for each source category. Additionally, no comment will be considered unless information is provided to corroborate and justify the need for the requested modification. For example, corroborating information in the case of the EGUs can be the inclusion of copies of each source's official same year EIA 860 or 861 form submissions that support the requested change. For non-EGUs, corroborating information can include 1995 operational and emissions information officially submitted (during that time period) by the source to a federal, State, or local government regulating entity.

Each request for modification of data for EGU sources must include the following information:

- Federal Information Placement System State Code.
- Federal Information Placement System (FIPS) County Code.
- Plant name.
- Plant ID numbers (ORIS code preferred, State agency tracking number also or otherwise).
- Unit ID numbers (a unit is a boiler or other combustion device).
- Unit type (also known as prime mover; e.g., wall-fired boiler, stoker boiler, combined cycle, combustion turbine, etc.).
- Primary fuel on a heat input basis.
- Maximum rated heat input capacity of unit.
- For electrical generating units, nameplate capacity of the largest generator the unit serves.
- For 1995 and 1996 ozone season heat inputs.
- 1996 (or most recent) average NO_X rate for the ozone season.
- Latitude and longitude coordinates.
- Stack parameter information (height, diameter, flow, etc.).
- Operating parameters (hours per day, seasonal throughput, etc.).
- Identification of specific change to the inventory, and
- The reason for the change.

Each request for modification of data for non-EGU point sources must include the following information:

- Federal Information Placement System State Code.
- Federal Information Placement System (FIPS) County Code.
- Plant name.
- Facility primary standard industrial classification code (SIC).
- Plant ID numbers (NEDS, AIRS/AFS, and State agency tracking number also or otherwise).
- Unit ID numbers (a unit is a boiler or other combustion device).
- Primary source classification code (SCC).
- Maximum rated heat input capacity of unit.
- 1995 ozone season or typical ozone season daily NO_X emissions.
- 1995 existing NO_X control efficiency.
- Latitude and longitude coordinates.
- Stack parameter information (height, diameter, flow, etc.).
- Operating parameters (hours per day, seasonal throughput, etc.).
- Identification of specific change to the inventory, and
- The reason for the change.

Each request for modification of data for stationary area and nonroad mobile sources must include the following information:

- Federal Information Placement System State Code.
- Federal Information Placement System (FIPS) County Code.
- Primary source classification code (SCC).
- 1995 ozone season or typical ozone season daily NO_X emissions.
- 1995 existing NO_X control efficiency.
- Identification of specific change to the inventory, and
- The reason for the change.

Each request for modification of data for highway mobile sources must include the following information:

- Federal Information Placement System State Code.
- Federal Information Placement System (FIPS) County Code.
- Primary source classification code (SCC) or vehicle type.
- 1995 ozone season or typical ozone season daily vehicle miles traveled (VMT).
- 1995 existing NO_X control programs.
- Identification of specific change to the inventory, and
- The reason for the change.

After this initial ''shake out'' period before submission of the SIP revisions, EPA will not adjust inventories or the resulting State budgets merely because some new information on a segment of EPA's projections comes to its attention. However, when EPA reviews each State's reports, it will pay special attention to the causes for any exceedance of the portions of the inventory that the State is controlling as a means to meet today's rule. If a State exceeds its budget because of greater-than-expected growth in areas not having additional controls, EPA would not penalize the State by requiring the State to offset those increased emissions. Rather, EPA would use the base case projections for all sectors (as revised after the initial period described above) and focus on whether the State had implemented the measures that its 1999 demonstration had shown would, based on those base case inventories, achieve the budget levels. Similarly, the rule would not penalize the State if components in the budget prove inaccurate because of changes in models (e.g., the release of an updated MOBILE model) or because of technical errors (e.g., the size of a unit was incorrectly identified in the inventory, a unit was double-counted, or the RACT level assumed in the base is different from what the State ultimately selected as RACT with EPA approval).

In the NPR, EPA also raised the question of what would happen if EPA adopts national measures beyond what EPA already assumed in the base case 2007 inventory. The EPA indicated that it could use either of two approaches in response: (1) States could receive credits for the real emission reductions that result from the new Federal measures and, therefore, implement a smaller portion of its planned emission reductions, or (2) States would be required to continue to implement the measures in their revised SIPs because affected States are required to continue to achieve emissions reductions equivalent to those which can be achieved through application of highly cost-effective control measures.

One commenter supported the emission reduction credit for State SIPs resulting from new Federal national measures adopted after the State emission budgets are defined but before 2007. According to this commenter, in such a case the State could implement a smaller portion of its planned emission reductions because of the reduction brought about by the Federal national rule. Another commenter said the EPA should allow full credit for all Federal measures and encouraged the EPA to timely implement and adopt all Federal measures. A State said States should be allowed to take full SIP credit for Federal measures which are implemented in these States. According to one commenter, not allowing States to take credit for new Federal measures would have the effect of downward ratcheting of NO_X budgets. Other States said new Federal measures not accounted for in the SIP call should not be used to offset State measures required to achieve the mandated NO_X emissions reductions.

The EPA has decided to adopt the second approach described above. Thus, EPA's adoption of a national measure not reflected in the base case 2007 inventory would not allow the State to avoid a measure that would otherwise be needed to demonstrate that the State will achieve the required reductions. As stated above, the SIP must prohibit all emissions that contribute significantly to downwind nonattainment and maintenance problems. The State therefore is required to eliminate an amount of emissions corresponding to what is achievable with the highly cost-effective measures identified in this notice. The comments received have not provided an adequate basis for concluding that EPA's adoption of an additional national measure justifies scaling back on that requirement. For that reason, EPA will not allow States to adjust the base case 2007 inventory inventories to reflect any such additional national measures. Rather, for these reports the States should continue to use the base case 2007 inventory set forth in this rule.

In the SNPR, EPA also discussed establishing a process for reassessing the State budgets for the post-2007 timeframe. Today's final rule is based on analyses using the most complete, scientifically-credible tools and data available for the assessment of transport. The EPA expects that there will be a number of updates and refinements in air quality methodologies and emissions estimation techniques over the next 10 years. Therefore, EPA intends to reassess ozone transport using the latest emissions and air quality monitoring data and the next generation of air quality modeling tools. The reassessment will include an evaluation of the effectiveness of the regional NO_X measures States have implemented in response to today's final rule. Modeling analyses will be used to evaluate whether additional local or regional controls are needed to address residual nonattainment in the post-2007 timeframe. The assessment will also examine differences in actual growth versus projected growth in the years up to 2007 as well as expected future growth throughout the entire OTAG region. The reassessment will also review advances in control technologies to determine what reasonable and cost-effective measures are available for purposes of controlling local and regional ozone problems. In addition, EPA will continue to look at the issues that surround the use of output-based State budget allocations. Based on this reassessment, EPA may establish new budget levels and allocation mechanisms for the post-2007 timeframe. The current budget levels and the measures used to comply with today's final rule will remain in effect until EPA takes action on establishing new State budgets.

6. Compliance Supplement Pool

The EPA has received comments expressing concern that some sources may encounter unexpected problems installing controls by the compliance deadline that, in turn, could cause unacceptable risks for a source and its associated industry. More specifically, commenters have expressed concerns related to the electricity industry. If unexpected problems arise for specific sources that are used to generate electricity, some commenters believe that compliance with the May 1, 2003 deadline could adversely impact the reliability of the electricity supply. Commenters that raised concerns regarding the compliance deadline generally supported additional compliance flexibility for the SIP call.

In both the NPR and SNPR, EPA solicited comment on a number of provisions that would provide additional flexibility to both States and sources for the requirements of the NO_X SIP call. In the NPR, EPA proposed that the NO_X SIP call would require full implementation of controls by no later than September 2002, but solicited comment on the range of implementation dates from between September 2002 and September 2004. In addition to the compliance deadline, EPA also solicited comment on the role of banking as a separate compliance flexibility for the NO_X SIP call. Banking may generally be defined as allowing sources that make emissions reductions beyond current requirements to save and use these excess reductions to exceed requirements in a later time period. Depending upon the design of a trading program, banking provisions can provide companies greater latitude for when controls are installed at particular sources. In the SNPR, EPA presented a range of options for incorporating banking in the NO_X Budget Trading Program including early reduction provisions and phasing in controls. The EPA received many comments supporting banking in the NO_X Budget Trading Program and also as a general flexibility mechanism that should be permissible for any State program used to comply with the NO_X SIP call.

In response to comments supporting an extended compliance deadline, EPA has moved the deadline from the proposed date of September 2002 in the NPR to May 1, 2003. As discussed further in Section V, this change provides sources 7–8 additional months for implementing control requirements while ensuring that controls are fully implemented by the 2003 ozone season. The EPA believes that the compliance date of May 1, 2003 for NO_X controls to be installed to comply with the NO_X SIP call is a feasible and reasonable deadline. See Section V.A.1. and the technical support document ''Feasibility of Installing NO_X Control Technologies By May 2003'' for further discussion.

To provide additional flexibility to States and sources for complying with the NO_X SIP call beyond the extension of the compliance deadline, EPA is establishing banking provisions and a compliance supplement pool in today's final rule. The banking provisions are outlined in Section III.F.7. The compliance supplement pool is a voluntary provision that provides flexibility to States in addressing concerns associated with full compliance by May 1, 2003. Each State will be able to use the pool to cover excess emissions of sources that are unable to meet the compliance deadline during the 2003 and 2004 ozone seasons. The pool may be used to credit sources that make early reductions and to directly delay the compliance deadline for specific sources. Credits issued from the compliance supplement pool will not be valid for compliance past the 2004 ozone season. The EPA established the compliance supplement pool by calculating one pool for the entire NO_X SIP call region. The pool was then allocated to the States in proportion to the size of the emissions reduction they are required to achieve under the NO_X SIP call so that each

State has its own compliance supplement pool. The size of each State's compliance supplement pool and the procedures that will apply to the use of the pool are described below.

a. Size of the Compliance Supplement Pool. The EPA believes it is important for the size of the pool to be capped. Capping the pool makes it possible to estimate the potential impact that the compliance supplement pool may have on NO_X emissions during the 2003 and 2004 ozone seasons. Furthermore, EPA does not anticipate problems for sources in meeting the May 1, 2003 deadline. If there are such cases, they should be relatively few in number. Therefore, the size of the pool only needs to be large enough to cover the limited potential for unexpected compliance delays.

Today's final rule sets the size of the regional compliance supplement pool at 200,000 tons. The EPA believes this is a reasonable size for the pool given the analyses that were used in establishing the State NO_X budgets for today's final rule. As discussed in Section V.A.1., EPA believes the most cost-effective control strategies available to comply with the proposed budgets include post-combustion controls (Selective Catalytic Reduction [SCR] and Selective Non-catalytic Reduction [SNCR]) and combustion controls (e.g., low NO_X burners, overfire air, etc.) on large electric generating units and large non-electric generating units. For the reasons cited in Section V.A.1., EPA estimates that the implementation of SCR controls is potentially more complicated and requires more time than SNCR or combustion controls and, therefore, would determine what the longest schedule would be for full implementation of the assumed NO_X controls. Since EPA estimates that a single SCR installation will take about 23 months, EPA expects the first SCR installations to be completed in 2001. Since compliance is required by 2003, one can assume 33 percent of SCR capacity will be installed each year from 2001 to 2003. The 200,000 ton number is sufficient to cover the excess emissions that must be offset if one year's worth of SCR installations were delayed by a year. Table III–3 shows each State's compliance supplement pool. The 200,000 tons were allocated to States in proportion to the size of the emissions reduction they are required to achieve under the NO_X SIP call. The EPA used this allocation methodology based on the assumption that the need for the pool would be directly related to the magnitude of the emissions reductions required in each State to comply with the NO_X SIP call.

TABLE III–3.—STATE COMPLIANCE SUPPLEMENT POOLS

[Tons]

State	Base	Budget	Tonnage reduction	Compliance supplement pool
Alabama	218,610	158,677	59,933	10,361
Connecticut	43,807	40,573	3,234	559
Delaware	20,936	18,523	2,413	417
District of Columbia	6,603	6,792	(189)	0
Georgia	240,540	177,381	63,159	10,919
Illinois	311,174	210,210	100,964	17,455
Indiana	316,753	202,584	114,169	19,738
Kentucky	230,997	155,698	75,298	13,018
Maryland	92,570	71,388	21,182	3,662
Massachusetts	79,815	78,168	1,648	285
Michigan	301,042	212,199	88,842	15,359
Missouri	175,089	114,532	60,557	10,469
New Jersey	106,995	97,034	9,960	1,722
New York	190,358	179,769	10,590	1,831
North Carolina	213,296	151,847	61,450	10,624
Ohio	372,626	239,898	132,728	22,947
Pennsylvania	331,785	252,447	79,338	13,716
Rhode Island	8,295	8,313	(18)	0
South Carolina	138,706	109,425	29,281	5,062
Tennessee	252,426	182,476	69,950	12,093
Virginia	191,050	155,718	35,332	6,108
West Virginia	190,887	92,920	97,967	16,937
Wisconsin	145,391	106,540	38,851	6,717
Total	4,179,751	3,023,113	....	200,000

b. State Distribution of the Compliance Supplement Pool. States have two options for making the pool available to sources. One option is to distribute some or all of the pool to sources that generate early reductions during ozone seasons prior to May 1, 2003. The second option is to run a public process to provide tons to sources that demonstrate a need for a compliance extension. A State wishing to use the compliance supplement pool may divide the State pool and make some of it available to sources through both options, or may use only one of the options for distributing the pool to sources prior to May 1, 2003 according to the procedures discussed below. Tons that are not distributed by a State prior to May 1, 2003 will be retired by EPA.

(1) Early Reduction Credits. The EPA encourages States to consider making the compliance supplement pool available to sources through an early reduction credit program. States may use early reduction credits as an incentive for sources to make NO_X emissions reductions prior to the 2003 ozone season that would otherwise not occur. By generating early credits or acquiring them from other sources, companies will be able to use the early reduction credits to extend the timeframe for achieving actual emissions reductions at specific sources that may require additional time. To establish an early credit program, States that participate in the NO_X Budget Trading Program may use the provisions

set forth in that trading program (See Section VII.F). States not participating in the NO_X Budget Trading Program are also free to develop their own rules for granting early reduction credits and recognizing the credits for compliance during the 2003 and 2004 ozone seasons. The procedures for establishing an early credit program are presented below in Section III.F.7.c.

(2) Direct Distribution to Sources. States may also distribute the compliance supplement pool directly to sources that demonstrate a need for the compliance supplement. Under this approach, sources would be responsible for demonstrating to the State and public that achieving compliance by May 1, 2003 would create undue risk either to its own operation or its associated industry. Before granting a direct distribution to a source, the State must provide the public an opportunity to comment on the validity of the need for direct distribution of the compliance supplement. The direct distribution process must be initiated and completed between September 30, 2002 and May 1, 2003. States which choose to grant early reduction credits cannot conduct the direct distribution until all early reduction credits have been issued by the State. By postponing the direct distribution until after September 2002, sources will have the maximum opportunity to achieve compliance, either through installation of controls or with early reduction credits, before using this option. States and the public will also be better positioned to determine legitimate requests after September 2002.

To ensure that direct distribution of the compliance supplement is only provided to sources that truly need a compliance extension, States are only permitted to give credits to an owner or operator of a source that demonstrates the following:

- The process of achieving compliance by May 1, 2003 would create undue risk for the source or its associated industry. For electric generating units, the demonstration should show that installing controls would create unacceptable risks for the reliability of the electricity supply during the time of installation. This demonstration would include a showing that it was not feasible to import electricity from other systems during the time of installation. Non-electric generating sources may also be eligible for the compliance supplement based on a demonstration of risk comparable to that described for the electricity industry.
- For a source subject to an early reduction credit program, it was not possible to compensate for delayed compliance by generating early reduction credits at the source or by acquiring credits generated by other sources.
- For a source subject to an emissions trading program, it was not possible to acquire allowances or credits for the 2003 ozone season from sources that will make reductions beyond required levels during the 2003 ozone season.

7. Banking

As noted in the NPR and SNPR, States have the flexibility to choose their own set of control measures to meet their Statewide NO_X budget established under the NO_X SIP call. States and sources have supported the use of emissions trading programs as a control measure for complying with the NO_X SIP call requirements. EPA has provided a model cap-and-trade program (NO_X Budget Trading Program) for large stationary sources that States can adopt as one option for establishing an emissions trading program. A number of commenters (both States and sources) have also expressed interest in pursuing alternative trading programs in addition to or as a substitute for the NO_X Budget Trading Program. One possible flexibility mechanism available to sources subject to an emissions trading program is the ability to bank emissions reductions. Banking may generally be defined as allowing sources that make emissions reductions beyond required levels to save and use these excess reductions to compensate for emitting emissions above required levels in a later time period. In the SNPR, EPA requested comment on whether and how banking should be incorporated into the design of the NO_X Budget Trading Program. In the proposal, four banking options were presented: (1) Banking would not be a feature; (2) banking would begin when the trading program begins (May 2003); (3) sources would be allowed to generate early reductions credits for use after the start of the program and banking would continue after the program begins; (4) banking would begin with the first phase of a two-phase trading program and continue thereafter (i.e., phased-in control requirements). The EPA also requested comment on options for managing the use of banked allowances in order to limit the potential for emissions to be significantly higher than budgeted levels because of banking. The EPA specifically proposed using a ''flow control'' mechanism in the latter two banking options where the potential exists for a large amount of banked allowances to be available for use at the start of the program.

a. Banking Starting in 2003. Comments for the NO_X Budget Trading Program were generally supportive of including banking in the trading program. Commenters noted that allowing sources to make excess reductions in one year and use these reductions to emit above required levels in a later year encourages early and cost-saving emission reductions, helps avoid end-of-season emissions spikes (because unused allowances retain their value for compliance in future years), and encourages more expedient development and implementation of NO_X control technology. Commenters pointed out that banking also provides sources flexibility in achieving emission reduction goals, allowing them to save allowances in years when the cost of achieving a given emission level is relatively low for use in years when the cost is relatively higher (for example, a year characterized by low availability of nuclear and hydro generation capacity would be a higher cost year). Thus, banking was seen by many commenters as a critical tool for sources to respond to uncertainty. Some commenters, however, expressed caveats along with their support for banking. They cited the need for some form of bank management to ensure that the use of banked allowances does not detract from the environmental goal of the NO_X SIP call. At least one commenter recommended that EPA identify banking as an area to be reviewed for problems during audits of the program to ensure it did not have a detrimental impact.

The EPA also received comments supporting banking that were not specific to the NO_X Budget Trading Program. Many commenters addressed the concept of banking when proposing alternative strategies for establishing and implementing the State budgets that were proposed in the NO_X SIP call. These comments regarded banking as a fundamental factor in establishing the timing and control level for the State budgets. With all other factors being equal, a NO_X SIP call that allows banking provides additional flexibility and cost savings to affected sources than a NO_X SIP call without banking. For this reason, many commenters included banking in their alternative proposals.

In order to provide additional flexibility to States and sources under the NO_X SIP call as discussed in section III.F.6., and recognizing that States may pursue alternative trading programs other than the NO_X Budget Trading Program, the Agency believes it is important to establish criteria for banking that would apply to all programs that States may use to comply with requirements of the NO_X SIP call.

Therefore, EPA is setting forth provisions in today's final rule that will allow banking in the NO_X Budget Trading Program and other State trading programs. Trading programs used to comply with the NO_X SIP call may allow banking to start in the first control period of the program, May 1 through September 30, 2003. Beginning in that control period, States may allow sources included in these programs to bank NO_X emissions reductions not otherwise required by the State's SIP, for compliance in future control periods. As outlined below, the banking provisions also require the use of a flow control mechanism beginning in 2004 and allow States to credit early reductions generated by sources prior to 2003 that may be used for compliance only in the 2003 and 2004 ozone seasons. The final rule for the NO_X Budget Trading Program conforms with these banking provisions. Additionally, alternative emissions trading programs used to comply with the SIP call will be subject to these banking criteria as well other applicable criteria in § 51.121 and any other applicable EPA guidance such as the Economic Incentive Program rules and guidance.

b. Management of Banked Allowances. Many utility and industry commenters generally opposed the use of discounts or constraints on banked allowances, arguing that such measures would reduce the incentives to control emissions beyond required levels. In addition, commenters felt the measures were overly complex and restrictive, as well as unnecessary, since the stringent control level proposed would serve as a barrier to overcontrol, precluding the establishment of a sizeable bank. Several commenters remarked that any decision regarding whether and to what extent a trading program should impose restrictions on the use of banked allowances should proceed from an analysis of the air quality effects of that use; in the absence of such an analysis, there would be little basis for imposing restrictions or for deciding what restrictions would properly address air quality effects. However, these commenters did not provide analyses demonstrating that the use of banked allowances in any given season would not be a problem in the context of the NO_X SIP call. One commenter pointed out specifically that the sheer magnitude of the SIP call region should preclude EPA from implementing a flow control management scheme similar to that used under the Ozone Transport Commission's (OTC) trading program, since protection of problem areas would not be feasible on such a large scale.

Several commenters who were opposed to the management of banked allowances, however, stated that if restrictions were to be imposed, they would favor flow control as the most cost-effective, least rigid means of management. A few commenters added that, if implemented, flow control should be applied on a source-by-source basis so as to avoid penalizing all of the participants in the trading program for the excess banking of individual participants. One commenter stated that if EPA concludes that there is an adequate basis for imposing some type of restriction, it should avoid placing any absolute limit on the amount of banked allowances that can be used in a given season. Another commenter suggested that if EPA chooses to propose managed banking, it should consider establishing an initial period without managed banking upon which a managed banking program can later be based if it turns out that "trading contributes to nonattainment." Several additional commenters, most notably northeastern States and a few environmental groups, supported the use of a flow control management system to discourage excess use of banked allowances in any one ozone season. One such commenter suggested that EPA conduct an analysis similar to that used by the OTC in determining the appropriate level of flow control for the SIP call region.

Based on the stated goal of the NO_X SIP call, to achieve specified limits on NO_X emissions for the purpose of reducing NO_X and ozone transport across State boundaries in the eastern half of the United States, EPA believes it is appropriate to place some limitation on the amount of emissions variability that may occur with banking, and therefore, occur with the transport of NO_X. At the same time, any limitations on banking should still fit within the market-based structure of trading programs, rather than imposing overly stringent limits that would potentially eliminate the advantages of having banking in the first place. For these reasons, EPA is including a provision in today's final rule requiring any State program used to comply with the requirements of the NO_X SIP call that allows banking to limit the potential effects of banking through a flow control mechanism as described below. The flow control mechanism will be applicable starting in the 2004 ozone season. In this year, unused credits from the compliance supplement pool as well as unused credits or allowances from the 2003 ozone season would be considered banked.

The EPA believes that the flow control mechanism serves as an important insurance policy against emissions variability in emissions trading programs used to comply with the NO_X SIP call. The mechanism as described below would only restrict the use of banked allowances or credits when a significant amount are used for compliance in a specific ozone season. Based on the analyses in the RIA, EPA believes that the flow control mechanism is set at a level that will allow sources to use banking without restriction. However, the flow control mechanism provides the extra security to downwind areas that banking will not result in significant increases of emissions above budgeted levels. The EPA also recognizes that a wide variety of emissions trading programs may be used by States. Therefore, the requirements for the flow control mechanism described below are intended to be general, thus allowing States the flexibility to adjust the flow control mechanism to fit the specific needs of each program. Section VII.F. also provides further discussion of the flow control mechanism and describes how it is incorporated into the NO_X Budget Trading Program.

The flow control mechanism allows the unlimited banking of emissions reductions by sources during and after 2003, but discourages the "excessive use" of banked allowances or credits by establishing either an absolute limit on the number of banked allowances or credits that can be used each season or a rate discounting the use of banked allowances or credits over a given level. The key issue with flow control is to establish the level at which flow control is triggered. In the SNPR, EPA solicited comment on establishing the level at 10 percent of the ozone season budget for the sources included in the trading program. This level was proposed because 10 percent seems to be a reasonable number that would allow a significant amount of banked allowances or credits to be used, but not so many as to jeopardize the intended effects of the NO_X SIP call in a given season. The EPA also proposed the 10 percent number because it is the level used for flow control in the OTC's trading program. Although some commenters questioned whether this number is appropriate for the NO_X SIP call region, commenters did not provide explicit analyses or recommendations for a different number. Thus, EPA continues to believe that 10 percent is a reasonable number and is including this in today's final rule. Based on the analyses in the RIA, EPA does not anticipate sources to bank above the 10 percent level. Therefore, this level should prevent significant emissions increases resulting from banking without restricting sources normal operations. The effect of flow control set at 10 percent of the trading program budget is that for a given season, sources may use banked allowances or credits for compliance without restrictions in an amount up to 10 percent of the NO_X budget for those sources in the trading program. Banked allowances or credits that are used in an amount greater than 10 percent of the NO_X budget for those sources will have restrictions that are described below.

The EPA believes it is necessary to provide flexibility to States for determining how to apply the 10 percent flow control in individual trading programs and for determining the appropriate restrictions for banked allowances or credits that are used in an amount greater than the 10 percent number. States have the flexibility to apply the flow control mechanism to specifically control the use of banked allowances or credits at each source or to apply the mechanism more broadly across the entire trading program. For example, by applying flow control at the source level, a State would allow each source participating in the trading program to use banked allowances without restrictions in an amount not greater than 10 percent of its allowable NO_X emissions for the ozone season. Conversely, flow control could be applied so that individual sources may use banked allowances or credits in an amount more than 10 percent without restrictions, but the total number used throughout the entire trading program (i.e., total number of banked credits or allowances used for compliance throughout all States participating in the trading program) could not exceed 10 percent of the allowable NO_X emissions for all sources in the trading program without restrictions. The net effect is the same under either approach—banked allowances or credits may be used each year without restrictions in an amount that does not exceed 10 percent of the allowable NO_X emissions for all sources covered by the trading program. The NO_X Budget Trading Program uses the latter approach. See Section VII.F. for more details.

The second issue for the flow control mechanism is to determine what restrictions should be placed on banked allowances or credits that are used in an amount greater than 10 percent of the allowable NO_X emissions for all sources covered by the trading program. Again, EPA is providing flexibility for the restrictions that States may use. States may use a discount that is no less than two-for-one, requiring sources to retire one additional banked allowance or credit for each banked allowance or credit used for compliance in an amount greater than the 10 percent level. Or States may set the 10 percent level as a hard cap and not allow any banked allowances or credits to be used in an amount greater than the 10 percent level. Although the discount option provides more flexibility to sources and more uncertainty regarding NO_X emissions in a given year, EPA believes both options serve as an acceptable restriction for limiting the variability of emissions associated with banking. As described in Section VII.F, the NO_X Budget Trading Program uses the 2-for-1 discount as the applicable restriction.

c. Early Reduction Credits. The majority of commenters for the NO_X Budget Trading Program generally supported the option of awarding early reduction credits. Commenters noted that the issuance of credits will provide cost savings and environmental benefits by encouraging early reductions, facilitate compliance with the budget by allowing sources to earn allowances that may be used to delay more stringent emission reductions, and stimulate the market by ensuring allowances are available for trading at the program start. Several commenters advocated making early reduction credits available for any reductions that exceed baseline controls, whereas other commenters supported early reduction credits only if they exceed the controls required under the SIP call, as was proposed by EPA. A few other commenters suggested levels between these two options. A few OTC States suggested that OTC allowances banked in Phase II (between 1999–2003 for reductions beyond an approximate 0.20 lb/mmBtu rate) could be used as early reduction credits in the NO_X Budget Trading Program, either one-for-one or at a discount ratio, depending on the level beyond which credits were awarded in the latter program. A few remaining commenters, concerned about the potential for creating or exacerbating ozone violations, supported early reduction credits and banking only if coupled with flow control.

Regarding the appropriate length of the period in which early reductions could be earned, some commenters supported EPA's proposed option in the SNPR of a two-year early reduction period, while others favored a three or four-year period. At least one commenter specifically recommended that the early reduction period start in January 1995, while another suggested September 1998. Several commenters rejected EPA's suggestion that early reduction credits be calculated as a set-aside from the first five years of allowances, arguing that treating the credits as set-asides would be inconsistent with the nature of early reduction credits. Conversely, a few other commenters felt the credits should be awarded from within State budgets to avoid budget inflation. Additional commenters criticized EPA's suggestion that if early reduction credits were awarded, they be awarded at the company level, arguing instead for individual source awards. One commenter stated that awards on a company basis would not address the load shifting concerns EPA cited, while another thought EPA could address the load shifting concern by basing credits on activity levels in a historic period rather than by shifting to a company-level award. Finally, at least one commenter felt that States should be able to independently establish parameters for awarding voluntary early reductions.

For the reasons set forth in Section III.F.7, Compliance Supplement Pool, EPA is allowing, but not requiring, States to grant early reduction credit to sources that reduce their ozone season NO_X emissions below levels specified by the State prior to the 2003 control period. The early reduction credits may be used by sources for compliance during the 2003 and 2004 ozone seasons. EPA believes that an early credit program can be helpful to encourage emissions reductions prior to the 2003 ozone season that would not be made without an economic incentive for the sources to act. Furthermore, the early credit program will provide additional allowances or credits for use during the 2003 and 2004 ozone seasons. By generating early credits or acquiring early credits from other sources that generated credits, companies would have greater latitude in determining when actual emissions reductions are achieved at specific sources. As discussed in Section III.F.7, this may be beneficial to some companies that are concerned about the time and effort required to install all necessary emissions controls prior to May 2003. States will be limited in the amount of early reduction credits that they may grant by the amounts set forth in Section III.F.7 Compliance Supplement Pool. The potential pool of credits that is available to each State is intended to be large enough to provide a real incentive for early reductions and enough flexibility to allow the installation of some control equipment, if necessary, past May 2003.

Section VII.F. of today's preamble outlines how the early credit program is being incorporated into the NO_X Budget Trading Program and how banked allowances from the OTC program may be integrated with this provision. States that develop alternative trading programs may craft their early reduction program to meet the needs of their specific trading program. The following outlines the general requirements that any early reduction program used to comply with the NO_X SIP call should meet. For an emission reduction to be eligible as an early reduction credit, it must meet the following criteria:

• Surplus—The reduction is not contained in the State's SIP or otherwise required by the CAA.

• Verifiable—The reduction can be verified as actually having occured.

• Quantifiable—The reduction is quantified according to procedures set forth by the State and approved by EPA. Early reduction credits generated by sources serving electric generators with a nameplate capacity greater than 25 MWe or greater or boilers, combustion turbines and combined cycle units with a maximum design heat input greater than 250 mmBtu/hr, should be quantified according to the monitoring provisions of part 75, subpart H as required in § 51.121(h)(1)(iv).

Beyond the above requirements, States are free to develop an early credit program that meets the needs of their specific trading program provided the State does not issue credits in an amount greater the size of the credit pool presented in Section III.F.7. A State's early credit program may be established for any ozone season occurring after a State's early credit rule is approved by EPA into the State's SIP revision and before May 1, 2003.

To ensure that a State does not issue an amount of early credits beyond the amount specified in each State's compliance supplement pool, EPA recommends that a State develop procedures to be used in case there is an over-subscription of the early credit pool. Possible options include granting early credits on a first-come, first-served basis or waiting until all applications are submitted and then discounting the early credits on a pro-rata basis so that the amount of early credits issued equals the size of the State's pool. States may also influence the amount of early credits that sources generate by considering what level of emissions reductions the State will recognize as early reductions. For example, a State may choose to issue early reduction credits for any reductions below applicable requirements. However, the State may choose to make the demonstration more stringent by requiring early reduction credits to be generated by reductions that are below a limit that is tighter than applicable requirements (e.g., grant early reductions that are 30 percent below applicable requirements or below a fixed level such as 0.20 lb/mmBtu).

In the SNPR, EPA also solicited comment on a phased-in NO_X Budget Trading Program that would begin in 2001, two years prior to the compliance date for the NO_X SIP call. In response to the proposal, most commenters that discussed the phase-in program option were generally opposed to it. Their primary argument was that such a program would effectively accelerate the compliance date for NO_X controls under the SIP call. A few commenters, however, still supported the phase-in approach as a means of mitigating the uncertainties inherent in the allowance market that would develop for the 2003 control period, allowing sources to gain experience prior to 2003. Some commenters specifically favored a phase-in approach only if it does not interfere with the 2003 ozone season compliance schedule, whereas others supported a phase-in approach as a means of reducing the burdens of the 2003 ozone season compliance schedule.

Today's final rule requires States to achieve the necessary emissions reductions by May 2003 and does not require States to phase-in controls prior to 2003. States that wish to phase-in controls prior to 2003 as a part of a State trading program may do this, but they are not required to do so to comply with the NO_X SIP call. States that establish a phased-in trading program in order to allow sources to generate early reduction credits will be subject to the requirements for early reductions as described above, including the requirement that a State may not grant an amount of early reductions in excess of the State's compliance supplement pool. For a discussion of how the Ozone Transport Commission's trading program may be integrated with the compliance supplement pool and the early reduction provisions, see Section VII.F, which describes the banking provisions of the NO_X Budget Trading Program.

G. Final Statewide Budgets

1. EGU

a. Description of Selected Approach. As described in Section III.B.3. of this notice, the EGU budget component is calculated based on applying a 0.15 lb/mmBtu emission limit to sources greater than 25 MWe. This limit is applied uniformly across all States that are covered by this SIP call. The higher of 1995 or 1996 heat input, grown to 2007 is used to calculate the budget component.

b. Summary of Budget Component. Both the 2007 electricity generating Base Case and the electricity generating Budget component were revised from the levels in the SNPR based on the changes described in Section III.B.3. of this notice. These revisions are shown in Tables III–4 and III–5. The difference between the revised 2007 Base Case and Budget emissions from the SNPR and the final Base Case and Budget emissions is shown in Table III–4. Negative changes indicate decreases. The final percent reduction from the 2007 Base Case to the Budget is shown in Table III–5.

TABLE III–4.—CHANGES TO REVISED SNPR BASE CASE AND BUDGET COMPONENTS FOR ELECTRICITY GENERATING UNITS

[Tons NO_X/season]

State	Revised base	Final base	Percent change	Revised budget	Final budget	Percent change
Alabama	85,201	76,900	–10	30,644	29,051	–5
Connecticut	7,048	5,600	–21	5,245	2,583	–51
Delaware	10,727	5,800	–46	4,994	3,523	–29
District of Columbia	236	*0	–100	152	207	36
Georgia	84,890	86,500	2	32,433	30,255	–7
Illinois	119,756	119,300	0	36,570	32,045	–12
Indiana	159,917	136,800	–14	51,818	49,020	–5
Kentucky	130,919	107,800	–18	38,775	36,753	–5

TABLE III–4.—CHANGES TO REVISED SNPR BASE CASE AND BUDGET COMPONENTS FOR ELECTRICITY GENERATING UNITS—Continued

[Tons NO_X/season]

State	Revised base	Final base	Percent change	Revised budget	Final budget	Percent change
Maryland	37,575	32,600	–13	12,971	14,807	14
Massachusetts	24,998	16,500	–34	14,651	15,033	3
Michigan	73,585	86,600	18	29,458	28,165	–4
Missouri	81,799	82,100	0	26,450	23,923	–10
New Jersey	17,484	18,400	5	8,191	10,863	33
New York	43,705	39,200	–10	31,222	30,273	–3
North Carolina	86,872	84,800	–2	32,691	31,394	–4
Ohio	167,601	163,100	–3	51,493	48,468	–6
Pennsylvania	120,979	123,100	2	45,971	52,000	13
Rhode Island	1,351	1,100	–19	1,609	1,118	–31
South Carolina	57,146	36,300	–36	19,842	16,290	–18
Tennessee	83,844	70,900	–15	26,225	25,386	–3
Virginia	51,113	40,900	–20	20,990	18,258	–13
West Virginia	76,374	115,500	51	24,045	26,439	10
Wisconsin	45,538	52,000	14	17,345	17,972	4
Total	1,568,655	1,501,800	–4	563,784	543,825	–4

*The base case for DC is actually projected to be 3 tons per season. The base case values in this table are rounded to the nearest 100 tons.

TABLE III–5.—FINAL NO_X BUDGET COMPONENTS AND PERCENT REDUCTION FOR ELECTRICITY GENERATING UNITS

[tons/season]

State	Final base	Final budget	Percent reduction
Alabama	76,900	29,051	62
Connecticut	5,600	2,583	54
Delaware	5,800	3,523	39
District of Columbia	*0	207	NA
Georgia	86,500	30,255	65
Illinois	119,300	32,045	73
Indiana	136,800	49,020	64
Kentucky	107,800	36,753	66
Maryland	32,600	14,807	55
Massachusetts	16,500	15,033	9
Michigan	86,600	28,165	67
Missouri	82,100	23,923	71
New Jersey	18,400	10,863	41
New York	39,200	30,273	23
North Carolina	84,800	31,394	63
Ohio	163,100	48,468	70
Pennsylvania	123,100	52,000	58
Rhode Island	1,100	1,118	–2
South Carolina	36,300	16,290	55
Tennessee	70,900	25,386	64
Virginia	40,900	18,258	55
West Virginia	115,500	26,439	77
Wisconsin	52,000	17,972	65
Total	1,501,800	543,825	64

*The base case for DC is actually projected to be 3 tons per season. The base case values in this table are rounded to the nearest 100 tons.

2. Non-EGU Point Sources

As indicated in the proposal and discussed earlier in this notice, EPA continues to believe that technically feasible control measures costing between an average of $1,000 to $2,000 per ozone season ton (1990 dollars) are highly cost-effective and therefore should be the basis for determining the significant amounts that must be eliminated by each covered jurisdiction. In the SNPR, EPA committed to examining alternatives that would limit the number of affected non-EGU sources for the purpose of establishing emissions budgets, yet still achieve the environmental objective of mitigating broad-scale ozone transport. The EPA examined alternatives that target reductions from the largest non-EGU source category groupings, and within each of the largest groupings applied the cost-effectiveness criteria. The resulting emissions budget covers the majority of emissions from large non-utility sources, and does not include reductions from small sources and sources that, as a group, are not efficient to control, or are already covered by other Federal measures (e.g., CAA § 112 MACT). The description below summarizes the budget approach for non-EGU point sources.

a. Description of Selected Approach.

(1) NO_X Budget Sources. The following approach is used to determine if a unit's emissions would be decreased as part of the budget calculation.

Industrial boilers, turbines, stationary internal combustion engines and cement manufacturing are the only non-EGU sources for which reductions are assumed in the budget calculation.

1. Use heat input capacity data for each source if the data are in the updated inventory.

2. If heat input capacity data are not available, use the default identification of small and large sources developed by EPA/Pechan for OTAG and also used to develop the NPR and SNPR budgets for source categories with heat input capacity fields (''default data'').

3. Emission reductions would be assumed if specific source heat input capacity data or default data indicate that a source is greater than 250 mmBtu/hr in the updated inventory.

4. If specific or default heat input capacity data are not available in the updated inventory (or not appropriate for a particular source category), emission reductions would be assumed if the unit's average summer day emissions are greater than one ton per day based on the updated inventory.

5. All others are ''small'' and no emission reductions are assumed.

It should be noted (as described earlier in this section) that no emissions reductions are assumed for point sources with capacities less than or equal to 250 mmBtu/hr but with emissions greater than 1 ton/day for purposes of calculating the budget. This is a change from the NPR which assumed RACT controls on units with capacities less than or equal to 250 mmBtu/hr and emissions greater than 1 ton/day.

(2) Control Levels. For purposes of calculating the State NO_X budgets for the relevant sources (described above), the following emissions decreases from uncontrolled levels were assumed:

1. Non-EGU boilers and turbines—60% decrease.

2. Stationary internal combustion engines—90% decrease.

3. Cement manufacturing plants—30% decrease.

These controls result in an overall reduction in emissions from all affected large non-EGU point sources of almost 40 percent (187,800 tons per season decrease).

Each State's budget is based on application of these controls beginning on May 1, 2003. The EPA recognizes that if States include these source categories in a regionwide trading program, as EPA encourages States to do, each State will comply with its budget through compliance of its sources with the requirements of the regionwide trading program. Of course, under the trading program, sources in a State may acquire or sell allowances that will, in turn, allow for higher or lower emissions levels for that State than assumed in this action. Because EPA has determined that the ambient effect of such a trading program across the region is consistent with the basis for including States in the SIP call (see discussion below at Section IV), EPA has structured its rule to allow a State to meet its budget by including the amount of emissions for which sources in the State hold allowances from out-of-State sources. Overall, total NO_X emissions in the region will be within the budget.

b. Summary of Budget Component. Both the 2007 Base Case and Budget component for non-electricity generating point sources were revised based on the changes described above. Changes to the 2007 base reflect changes in the base year (1995) emissions and changes in growth factors. Changes to the budget components reflect these changes as well as the change in level of control. These resulting budget components are shown in Tables III–5 and III–6. The difference between the 2007 Base Case and Budget emissions as revised in the SNPR and the final Base Case and Budget emissions for non-electricity generating point sources is shown in Table III–6. Negative changes indicate decreases. The final percent reduction from the 2007 Base Case to the Budget is shown in Table III–7.

TABLE III–6.—CHANGES TO REVISED BASE CASE AND BUDGET COMPONENTS FOR NON-ELECTRICITY GENERATING POINT SOURCES

[Tons NO_X/season]

	Revised base	Final base	Percent change	Revised budget	Final budget	Percent change
Alabama	48,187	49,781	3	24,416	37,696	54
Connecticut	5,254	5,273	0	3,103	5,056	3
Delaware	5,276	1,781	−66	2,271	1,645	−28
District of Columbia	311	310	0	259	292	13
Georgia	33,939	33,939	0	14,305	27,026	89
Illinois	65,351	55,721	−15	40,719	42,011	3
Indiana	51,839	71,270	37	29,187	44,881	54
Kentucky	19,019	18,956	0	11,996	14,705	23
Maryland	10,710	10,982	3	5,852	7,593	30
Massachusetts	9,978	9,943	0	6,207	9,763	57
Michigan	61,656	79,034	28	35,957	48,627	35
Missouri	12,320	13,433	9	9,012	11,054	23
New Jersey	22,228	22,228	0	12,786	19,804	55
New York	20,853	25,791	24	14,644	24,128	65
North Carolina	34,412	34,027	−1	19,267	25,984	35
Ohio	53,329	53,241	0	30,923	35,145	14
Pennsylvania	74,839	73,748	−1	41,824	65,510	57
Rhode Island	327	327	0	327	327	0
South Carolina	34,994	34,740	−1	18,671	25,469	36
Tennessee	67,774	60,004	−11	34,308	35,568	4
Virginia	25,509	39,765	56	10,919	27,076	148
West Virginia	42,733	40,192	−6	21,066	31,286	49
Wisconsin	21,263	22,796	7	11,401	17,973	58
Total	722,101	757,281	5	399,416	558,618	40

TABLE III–7.—FINAL NO_X BUDGET COMPONENTS AND PERCENT REDUCTION FOR NON-ELECTRICITY GENERATING POINT SOURCES

[Tons/season]

	Final base	Final budget	Percent reduction
Alabama	49,781	37,696	24
Connecticut	5,273	5,056	4
Delaware	1,781	1,645	8
District of Columbia	310	292	6
Georgia	33,939	27,026	20
Illinois	55,721	42,011	25
Indiana	71,270	44,881	37
Kentucky	18,956	14,705	22
Maryland	10,982	7,593	31
Massachusetts	9,943	9,763	2
Michigan	79,034	48,627	38
Missouri	13,433	11,054	18
New Jersey	22,228	19,804	11
New York	25,791	24,128	6
North Carolina	34,027	25,984	24
Ohio	53,241	35,145	34
Pennsylvania	73,748	65,510	11
Rhode Island	327	327	0
South Carolina	34,740	25,469	27
Tennessee	60,004	35,568	41
Virginia	39,765	27,076	32
West Virginia	40,192	31,286	22
Wisconsin	22,796	17,973	21
Total	757,281	558,618	26

3. Mobile and Area Sources

a. Description of Selected Budget Approach. As discussed in Section III.D.3 of the notice, EPA proposed highway budget components based on projected highway vehicle emissions in 2007 from a base year of 1990, assuming implementation of those measures incorporated in existing SIPs, such as inspection and maintenance programs and reformulated fuels, measures already implemented federally, and those additional measures expected to be implemented federally by 2007. As discussed in Section III.E of this notice, EPA proposed nonroad mobile source budget components based on projected nonroad mobile source emissions in 2007 from a base year of 1990. These projections were developed by estimating the emissions expected in 2007 from all nonroad engines, assuming implementation of those measures incorporated in existing SIPs, measures already implemented federally, and those additional measures expected to be implemented federally. For area sources, no cost-effective control measures were identified in the NPR. Because no comments were received that demonstrate that additional controls for highway, nonroad, or area sources are both feasible and highly cost-effective, the final budgets are based on the same levels of controls that were proposed.

b. Summary of Budget Component. Changes were made to the baseline stationary area, nonroad and highway mobile source budget data as discussed in Sections III.D. and III.E. of this notice. Budget components were calculated using the updated baseline and the controls discussed above. The resulting final budget components for these sectors are contained in Tables III–7, III–8, and III–9 below, along with the difference between the proposed Budget emissions and the final Budget emissions. The budget components are not compared to the 2007 base because no reductions were calculated beyond the base case. In the NPR and SNPR, EPA used a 2007 CAA baseline for these source sectors. Because the measures that are assumed in the budgets for these sectors are measures that would occur in the absence of the SIP call, EPA believes that it is more appropriate to use the budget level for these source sectors as the baseline and compare the total budgets to this revised baseline.

TABLE III–8.—FINAL NO_X BUDGET COMPONENTS FOR STATIONARY AREA SOURCES

[Tons/season]

	Proposed budget	Final budget	Percent change
Alabama	25,229	25,225	0
Connecticut	4,587	4,588	0
Delaware	1,035	963	−7
District of Columbia	741	741	0
Georgia	11,901	11,902	0
Illinois	7,270	7,822	8
Indiana	25,545	25,544	0
Kentucky	38,801	38,773	0
Maryland	8,123	4,105	−49
Massachusetts	10,297	10,090	−2

TABLE III–8.—FINAL NO_X BUDGET COMPONENTS FOR STATIONARY AREA SOURCES—Continued

[Tons/season]

	Proposed budget	Final budget	Percent change
Michigan	28,126	28,128	0
Missouri	6,626	6,603	0
New Jersey	11,388	11,098	−3
New York	15,585	15,587	0
North Carolina	9,193	10,651	16
Ohio	19,446	19,425	0
Pennsylvania	17,103	17,103	0
Rhode Island	420	420	0
South Carolina	8,420	8,359	−1
Tennessee	11,991	11,990	0
Virginia	25,261	18,622	−26
West Virginia	4,901	4,790	−2
Wisconsin	10,361	8,160	−21
Total	302,350	290,689	−4

TABLE III–9.—FINAL NO_X BUDGET COMPONENTS AND PERCENT REDUCTION FOR NONROAD SOURCES

[Tons/season]

	Proposed budget	Final budget	Percent change
Alabama	18,727	16,594	−11
Connecticut	9,581	9,584	0
Delaware	4,262	4,261	0
District of Columbia	3,582	3,470	−3
Georgia	22,714	21,588	−5
Illinois	56,429	47,035	−17
Indiana	27,112	22,445	−17
Kentucky	22,530	19,627	−13
Maryland	18,062	17,249	−4
Massachusetts	19,305	18,911	−2
Michigan	24,245	23,495	−3
Missouri	19,102	17,723	−7
New Jersey	21,723	21,163	−3
New York	30,018	29,260	−3
North Carolina	18,898	17,799	−6
Ohio	42,032	37,781	−10
Pennsylvania	29,176	25,554	−12
Rhode Island	2,074	2,073	0
South Carolina	12,831	11,903	−7
Tennessee	47,065	44,567	−5
Virginia	25,357	21,551	−15
West Virginia	10,048	10,220	2
Wisconsin	15,145	12,965	−14
Total	500,018	456,818	−9

TABLE III–10. FINAL NO_X BUDGET COMPONENTS AND PERCENT REDUCTION FOR HIGHWAY VEHICLES

[Tons/season]

	Proposed budget	Final budget	Percent change
Alabama	56,601	50,111	−11
Connecticut	17,392	18,762	8
Delaware	8,449	8,131	−4
District of Columbia	2,267	2,082	−8
Georgia	77,660	86,611	12
Illinois	77,690	81,297	5
Indiana	66,684	60,694	−9
Kentucky	46,258	45,841	−1
Maryland	28,620	27,634	−3
Massachusetts	23,116	24,371	5
Michigan	81,453	83,784	3
Missouri	55,056	55,230	0
New Jersey	39,376	34,106	−13
New York	94,068	80,521	−14

TABLE III–10. FINAL NO_X BUDGET COMPONENTS AND PERCENT REDUCTION FOR HIGHWAY VEHICLES—Continued

[Tons/season]

	Proposed budget	Final budget	Percent change
North Carolina	73,056	66,019	−10
Ohio	92,549	99,079	7
Pennsylvania	73,176	92,280	26
Rhode Island	5,701	4,375	−23
South Carolina	49,503	47,404	−4
Tennessee	67,662	64,965	−4
Virginia	79,848	70,212	−12
West Virginia	21,641	20,185	−7
Wisconsin	41,651	49,470	19
Total	1,179,477	1,173,163	−1

4. Potential Alternatives to Meeting the Budget

The EPA believes that there are additional control measures and alternative mixes of controls that a State could choose to implement by May 1, 2003. Examples of such measures are described below and illustrate that options are potentially available in several source categories.

The EPA believes that, with respect to EGUs, there is a large potential for energy efficiency and renewables in the NO_X SIP call region that reduce demand and provide for more environmentally-friendly energy resources. For example, if a company replaces a turbine with a more efficient one, the unit supplying the turbine would reduce the amount of fuel (heat input) the unit combusts and would reduce NO_X emissions proportionately, while the associated generator would produce the same amount of electricity. Renewable energy source generation includes hydroelectric, solar, wind, and geothermal generation. EPA recognizes that promotion of energy efficiency and renewables can contribute to a cost-effective NO_X reduction strategy. As such, EPA encourages States in the NO_X SIP call region to consider including energy efficiency and renewables as a strategy in meeting their NO_X budgets. One way to achieve this goal is by including a provision within a State's NO_X Budget Trading Rule that allocates a portion of a State's trading program budget to implementers of energy efficiency and renewables projects that reduce energy-related NO_X emissions during the ozone season. Another is to include energy efficiency and renewables projects as part of a State's implementation plan.

The EPA is working to develop guidance on how States can integrate energy efficiency into their SIPs by both of these mechanisms. The guidance will present EPA's current thinking on the important elements to include in a functional system that allocates a portion of a State's trading program budget to implementers of energy efficiency and renewables projects within the context of the NO_X Budget Trading Program. In addition, EPA will issue guidance outlining procedures for including energy efficiency and renewables projects in a State's SIP as control strategies for achieving the State's NO_X budget, separate from the NO_X Budget Trading Program. EPA plans to issue these guidance documents in the Fall of 1998 so that they will be available to States early in their SIP planning process.

With respect to non-EGUs, individual States could choose to require emissions decreases from sources or source categories that EPA exempted from the budget calculations. For example, there are many large sources for which EPA lacked enough information to determine potential controls and emissions reductions; States may have access to such information and could choose to apply cost-effective controls. In addition, States could choose to regulate one or more of the non-EGU stationary sources or source categories which EPA had exempted because emissions were relatively low considering other source categories in the 23 jurisdictions. In individual States, emissions from such sources could be a high percentage of uncontrolled emissions and, thus, be subject to efficient, cost-effective control for that particular State. Further, States may take other approaches to developing their budgets, such as cutoffs based on horsepower rather than tons per day, since they might have access to data that EPA did not have for all 23 jurisdictions.

With respect to mobile sources, States could implement other NO_X control measures in lieu of the controls described earlier in this section. For example, vehicle inspection and maintenance programs can provide significant NO_X reductions from highway vehicles. Additional NO_X reductions can be obtained by opting into the reformulated gasoline program, by implementing measures to reduce the growth in VMT, and by implementing programs to accelerate retirement of older, higher-emitting highway vehicles and nonroad equipment.

5. Statewide Budgets

The revised Statewide budgets that reflect the changes to the base year inventory and growth factors for all sectors and the revised control levels for the non-EGU point source sector described above are shown in Table III–11. For the 23 jurisdictions combined, the budgets result in a 28 percent reduction from the base case. In the NPR and SNPR the percent reduction was 35 percent. The difference in the percent reduction is due to several factors. First, in the NPR and SNPR reductions from certain highway and nonroad controls were assumed to occur as a result of measures implemented between promulgation of this rule and 2007. These measures include National Low Emission Vehicle Standards, the 2004 Heavy-Duty Engine Standards, the Federal Small Engine Standards, Phase II, Federal Marine Engine Standards (for diesel engines of greater than 50 horsepower), Federal Locomotive Standards, and the Nonroad Diesel Engine Standards. These controls were reflected in the budget but were not included in the base case. For the final rule, EPA determined that these measures should be included in the base case, rather than the budgets, because the measures would be implemented even in the absence of this rulemaking. Based on the emission levels that were used in the SNPR, the effect of using this approach to setting the base case is to decrease the percent reduction from 35 percent to approximately 31 percent.

The additional change in the percent reduction (from 31 percent to 28 percent) is primarily due to EPA's decision not to assume controls for several non-EGU source categories and to change the level of control for those non-EGU categories for which controls are assumed. Although the overall percent reduction went from 35 percent to 28 percent, the difference between the budget proposed in the SNPR and the final budgets in today's notice is less than 3 percent.

TABLE III–11.—REVISED STATEWIDE NO_X Budgets

[Tons/season]

State	Base	Budget	Percent reduction
Alabama	218,610	158,677	27
Connecticut	43,807	40,57	37
Delaware	20,936	18,523	12
District of Columbia	6,603	6,792	−3
Georgia	240,540	177,381	26
Illinois	311,174	210,210	32
Indiana	316,753	202,584	36
Kentucky	230,997	155,698	33
Maryland	92,570	71,388	23
Massachusetts	79,815	78,168	2
Michigan	301,042	212,199	30
Missouri	75,089	114,532	35
New Jersey	106,995	97,034	9
New York	190,358	179,769	6
North Carolina	213,296	151,847	29
Ohio	372,626	239,898	36
Pennsylvania	331,785	252,447	24
Rhode Island	8,295	8,31	30
South Carolina	138,706	109,425	21
Tennessee	252,426	182,476	28
Virginia	191,050	155,718	18
West Virginia	190,887	92,920	51
Wisconsin	145,391	106,540	27
Total	4,179,751	3,023,113	28

IV. Air Quality Assessment

A. Assessment of Proposed Statewide Budgets

In the SNPR, EPA documented the estimated ozone benefits of the proposed Statewide NO_X budgets based on an air quality modeling analysis. The major findings of that analysis are as follows:

(1) The emissions reductions associated with the proposed Statewide budgets are predicted to produce large reductions in both 1-hour and 8-hour concentrations in areas which currently violate the NAAQS and which would likely continue to have violations in the future without the SIP call budget reductions.

(2) Looking at individual ozone ''problem areas'' considered by OTAG shows similar results, based on the available metrics.

(3) Any ''disbenefits'' due to the NO_X reductions associated with the budgets are expected to be very limited compared to the extent of the benefits expected from these budgets.

(4) Even though the budgets are expected to reduce 1-hour and 8-hour ozone concentrations across all 23 jurisdictions, nonattainment problems requiring additional local control measures will likely continue in some areas currently violating the NAAQS.

(63 FR 25903)

B. Comments and Responses

The EPA received numerous comments on the air quality modeling of the proposed NO_X budgets. The following is a summary of the main comments and EPA's responses.

Comment: Commenters stated that the emissions inventories used for modeling were flawed because EPA's projection of the base year emissions to 2007 improperly treated growth for certain electric generation units by growing these units beyond their design capacity.

Response: The EPA agrees with this comment and has revised the 2007 emissions projections for modeling to take this factor into account. For the modeling described in the SNPR, EPA applied State-level growth factors uniformly to existing sources in each State. This did not account for maximum capacity and could have resulted in sources being modeled with emissions that were higher than their actual capacity would allow. For the modeling described in this notice, EPA has revised the projection procedures to use IPM to allocate growth to existing units considering their design capacity. As described below, EPA has remodeled the 2007 Base Case and the Statewide budgets using this revised inventory and found that the conclusions from the revised runs do not differ from those based on the SNPR model runs of these budgets.

Comment: Commenters stated that EPA's modeling in the SNPR examined the impacts of the budgets applied regionwide (i.e., for each State for which a budget is required), rather than the impacts on downwind nonattainment of the budgets applied only in upwind States. Therefore, according to the commenters, this modeling is not useful for indicating the impact of the State budgets on downwind nonattainment or maintenance problems.

Response: The EPA is well aware that many States in the SIP Call region are both upwind and downwind States, that is, they are upwind of certain nonattainment areas and downwind from other States. For example, Pennsylvania is upwind of New York City, and emissions from Pennsylvania sources significantly contribute to this nonattainment problem; and

Pennsylvania is downwind of several States, emissions from which significantly contribute to Philadelphia's nonattainment problem.

The EPA is further aware that modeling analyses that evaluate emissions reductions in each State affected by today's rulemaking do not isolate the precise impact of emissions reductions from each upwind State on nonattainment in a State that is itself both an upwind and downwind State. That is, the emissions reductions in that upwind/downwind area impact its own nonattainment problems. To return to the example noted above, because emissions reductions in Pennsylvania affect Philadelphia's air quality, modeling Pennsylvania's emissions reductions along with emissions reductions in all other affected States does not isolate the impact of emissions reductions from States upwind of Pennsylvania on Philadelphia's air quality. As a result, EPA is aware that the regionwide modeling of different budget levels does not indicate the differential impact on downwind areas of higher budget levels as compared to lower budget levels in upwind areas.

Nevertheless, EPA believes that regionwide modeling of the State budgets is a useful indication of the overall impacts of various budget levels. Today's rulemaking requires regionwide emissions reductions, which will carry certain costs and will have certain impacts viewed on a State-by-State basis and on a regionwide basis. The multi-State budgets promulgated today mean that in a State that is both upwind and downwind of other States, such as Pennsylvania, the air quality will, in fact, be improved by the emissions reductions in upwind States and by the reductions within the States that are required to improve air quality further downwind. Thus, it is necessary to consider the upwind emissions reductions together with the downwind emissions reductions in order to fully evaluate the air quality impacts of the Statewide budgets. Regionwide modeling is the only available approach to indicate these ''real world'' impacts in individual States, as well as allow an assessment of those impacts in light of their costs. Accordingly, this modeling is useful in evaluating the overall impacts of the alternative budget levels considered in the course of the rulemaking. The EPA believes that a comparison of the overall impacts of alternative budget levels, in turn, serves as a means to confirm whether the budget levels promulgated in today's rulemaking yield meaningful air quality benefits. Moreover, EPA has conducted other modeling which indicates the impact of budget-level emissions on air quality downwind, as discussed below.

Comment: Commenters stated that EPA should have modeled the proposed budgets on a State-by-State basis in order to assess the downwind benefits of applying the budgets in each State.

Response: The EPA performed a multi-factor analysis to determine the amount of a State's emissions that significantly contribute to downwind nonattainment and what the resulting State budget should be. This is discussed in detail in Section II.C., Weight of Evidence Determination of Covered States. Specifically, EPA determined that emissions from all sources in certain States contribute to downwind problems, but that only a portion of those emissions—in some cases, a relatively small portion—may be reduced through highly cost-effective controls. The EPA established a budget for each State based on the elimination of these emissions. After EPA established the budgets, EPA performed air quality modeling to quantify the overall ozone benefits of the budgets applied in all upwind States on selected downwind areas. This modeling is described below. The EPA considered the results of this modeling as an additional piece of evidence in the analysis to confirm that the amount of emissions reductions from upwind States collectively provide meaningful reductions in nonattainment downwind.

For the purposes of this modeling it is sufficient to model the budgets collectively, and not State-by-State, to demonstrate that the intended benefits of the budgets are achieved. Commenters who recommended State-by-State modeling generally argued that it would indicate that the reductions from a particular State would have a relatively small impact downwind, particularly compared to the impact of local reductions or reductions from other upwind States. In general, such a modeling result could stem from the relatively small amount of emissions reductions required of a particular upwind State under the SIP Call, due to EPA's decision to base the budgets on cost-effective controls rather than, more expensive controls. However, EPA's air quality modeling of the ambient impact of the required budgets in the upwind States on downwind nonattainment (discussed below) shows that even if the downwind ambient impact of the required reductions from a particular upwind State were small, that impact, when combined with the impact from the reductions required from other upwind States, provides meaningful downwind benefits. Ozone air quality problems are caused by the collective contribution from numerous sources over a large geographic area, so that it is appropriate to assess the impact of reductions from a particular upwind State in combination with reductions from other upwind States. The downwind air quality benefits from these upwind reductions confirm the appropriateness of the promulgated budgets.

Comment: Commenters stated that EPA should have modeled alternative control options to determine if less stringent controls, either applied uniformly or on a subregional basis (i.e., multi-State subregional variations in control levels), would provide air quality benefits essentially equivalent to EPA's proposal. In addition, commenters submitted a considerable number of new modeling analyses intended to show that (a) sufficient downwind ozone benefits can be achieved with control levels less stringent than those associated with EPA's proposal; (b) controls applied in certain upwind States, when examined on a State-by-State basis, do not provide ''significant'' benefits in any downwind nonattainment area; and/or (c) NO_X controls increase ozone locally in some areas and these increases are greater than the predicted decreases. In addition to new control strategy modeling, commenters submitted modeling that pertains to the finding of significant contribution. The EPA's responses to this modeling are discussed in Section II.C., Weight of Evidence Determination of Covered States and in the Response to Comment document.

Response: In response to the comments on the need to model alternative controls, EPA has modeled alternative budgets based on several EGU and non-EGU control options. For the most part, these alternative budgets were modeled regionwide in order to assess, as discussed above, the benefits considering both downwind and upwind emissions reductions, collectively. Further, as discussed below, EPA modeled several other types of scenarios including runs to assess the impacts of the proposal applied in upwind States on several downwind areas. The EPA's modeling analyses are summarized below and described in detail in the Air Quality Modeling TSD.

Regarding the new control strategy modeling submitted by commenters, EPA has reviewed this information in the same way it reviewed the new modeling on ''significant contribution'', as described in Section II.C., Weight of Evidence Determination of Covered States. Specifically, EPA reviewed the commenters' modeling to determine and assess (a) the technical aspects of the models that were applied; (b) the treatment of emissions inventories; (c) the types of episodes modeled; (d) the methods for aggregating, analyzing, and presenting the results; (e) the completeness and applicability of the information provided; and (f) whether the technical evidence supports the arguments made by the commenters. A summary of this review is discussed next. For the most part, the commenters used either the UAM–V model and/or the CAM_X model to assess the relative impacts of various NO_X control strategies. As discussed in Section II.C. Weight of Evidence Determination of Covered States, modeling results from both models are viewed by EPA as technically acceptable. Concerning the emissions used for modeling, most commenters stated that they used the EPA SNPR or IPM-derived 2007 Base Case emissions as a starting point for developing emissions for the control scenarios. However, the commenters did not provide emissions data summaries in order for EPA to confirm which inventories were used in the modeling. Also, the commenters did not document in detail how they applied the controls to the emissions inventory.

Most of the control strategy modeling submitted by commenters was performed for the July 1995 episode although a few commenters performed modeling for all four OTAG episodes and one commenter provided modeling for a non-OTAG episode in June of 1991. As discussed in Section II.C., and in the Response to Comment document, EPA's ability to fully evaluate and utilize the modeling submitted by commenters was hampered in some cases because only limited information on the results was provided.

The EPA considered the strengths and limitations in the commenters' modeling analyses in evaluating whether the technical evidence presented in the comments supports the arguments made by the commenters. A detailed review of the commenters' modeling is contained in the Response to Comment document. In general, this review indicates that (a) downwind ozone benefits increase as greater NO_X controls are applied to sources in upwind States, (b) emissions reductions at the level of the SIP Call, even when evaluated on an individual State-by-State basis, reduce ozone in downwind nonattainment areas, (c) the net benefits of NO_X control at the level of the SIP Call outweigh any local disbenefits, and (d) upwind NO_X reductions tend to mitigate local disbenefits in downwind areas. Thus, based on this evaluation, EPA generally found that the submitted modeling did not refute the overall conclusions EPA has drawn concerning the impacts of NO_X emissions in the relevant geographic areas. However, because the extent and level of detail in the information presented by the commenters was, in many cases, limited and/or qualitative, the EPA decided to model a number of alternative control scenarios for all four OTAG episodes. The results of EPA's modeling of the impacts of alternative NO_X controls are described next.

C. Assessment of Alternative Control Levels

As indicated above, EPA has remodeled the Base Case and Statewide budgets using updated EGU emissions which do not exceed the capacity of individual units. In addition, EPA has performed modeling of various alternative EGU and non-EGU control options. Further, EPA has modeled the benefits in selected downwind areas of the budgets applied in upwind States. The results of EPA's modeling analyses are summarized below and described in more detail in the Air Quality Modeling TSD.

1. Scenarios Modeled

As part of EPA's assessment, a 2007 SIP Call Base Case (hereafter referred to as the "Base Case") and eight emissions scenarios were modeled, as listed in Table IV–1. The first four scenarios (i.e. "0.25", "0.20", "0.15t", and "0.12") were designed to evaluate alternative EGU and non-EGU controls applied uniformly in all 23 jurisdictions. For each of these four scenarios, EGU emissions were determined assuming a cap-and-trade program across all 23 jurisdictions. The 0.15t scenario reflects the SIP Call proposal for both non-EGU and EGU sources. Note that non-EGU controls were modeled at the level of the proposal for all scenarios except for the 0.25 scenario for which less stringent controls were assumed.

TABLE IV–1.—EMISSIONS SCENARIOS MODELED

Base Case:

2007 SIP Call Base Case [1]

Point Sources: CAA Controls.

Area Sources: OTAG "Level 1" Controls.

Highway Vehicles: OTAG "Level 0" Controls.

Control scenarios	Electricity generation units—EGUs	Non-EGU point sources [2]
0.25	0.25 lb/mmBtu, interstate trading	60% reduction for large sources.
0.20	0.20 lb/mmBtu, interstate trading	70% reduction for large sources, RACT for medium sources[2].
0.15t	0.15 lb/mmBtu, interstate trading	70% reduction for large sources, RACT for medium sources.
0.12	0.12 lb/mmBtu, interstate trading	70% reduction for large sources, RACT for medium sources.
0.15nt	0.15 lb/mmBtu, intrastate trading	70% reduction for large sources, RACT for medium sources.

Downwind Scenarios for Analysis of "Transport":

(1) 0.15nt EGU and non-EGU controls in the Northeast [3]; 2007 Base Case emissions elsewhere.

(2) 0.15nt EGU and non-EGU controls in Georgia; 2007 Base Case emissions elsewhere.

(3) 0.15nt EGU and non-EGU controls in Illinois, Indiana, and Wisconsin; 2007 Base Case emissions elsewhere.

[1] See Table IV–2 for a listing of Base Case control measures.

[2] Reductions are from 2007 "uncontrolled" emissions. Non-EGU sources >250mmBtu/hr are considered as "large"; sources <250mmBtu/hr, but >1tpd are considered as "medium". The non-EGU point source controls assumed for purposes of this modeling do not match the levels assumed for the purpose of calculating the final budgets.

[3] Northeast includes Connecticut, Delaware, District of Columbia, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Rhode Island.

The EPA also modeled a 0.15 intrastate trading scenario, ''0.15nt'', which was constructed with EGU emissions that meet each State's budget without interstate trading. In developing the EGU emissions for this scenario, intrastate trading among sources in a State was allowed to occur. The benefits of the 0.15nt scenario compared to those from the 0.15t scenario were examined to determine whether an interstate trading program would affect the overall benefits of the proposal.

The last three scenarios in Table IV–1 were designed to evaluate the downwind benefits resulting from reductions in transport due to the budgets in upwind States. Each of these scenarios constitutes a separate modeling run that applies the 0.15nt scenario in a different downwind area. For example, in the ''nt15NE'' scenario, the 0.15nt emissions budgets were applied only in those Northeast States subject to the SIP Call. The predictions from each of these three modeling runs for specific downwind areas were compared to the Base Case to estimate the impacts of the budgets applied only within the downwind area. The predictions from these three runs were then compared to the 0.15nt scenario across all 23 jurisdictions to estimate the additional benefits in each downwind area due to reductions in transport resulting from the budgets applied in both upwind and downwind States.

2. Emissions for Model Runs

As indicated in Table IV–1, Base Case emissions for area sources (including nonroad), highway vehicles, and non-EGU sources represent a combination of OTAG emissions data for various control levels. This includes CAA controls on non-EGU point sources, OTAG ''level 1'' controls on area sources, and ''level 0'' controls on highway vehicles. The control measures included in the Base Case for each source category are listed in Table IV–2. These modeling runs were performed before changes were made to the inventory in response to comments. For the 23 jurisdictions as a whole, the Base Case NO_X emissions that were modeled are 2 percent higher than the final Base Case emissions that reflect changes made in response to comments.

TABLE IV–2.—2007 SIP CALL BASE CASE CONTROLS

EGUs:
Title IV Controls [phase 1 and 2].
—250 Ton PSD and NSPS.
—RACT & NSR in non-waived NAAs.
Non-EGU Point:
—NO_X RACT on major sources in non-waived NAAs.
—250 Ton PSD and NSPS.
—NSR in non-waived NAAs.
—CTG and Non-CTG VOC RACT at major sources in NAAs and OTR.
—New Source LAER.
Stationary Area:
—Two Phases of VOC Consumer and Commercial Products and One Phase of Architectural Coatings controls.
—VOC Stage 1 and 2 Petroleum Distribution Controls in NAAs.
—VOC Autobody, Degreasing and Dry Cleaning controls in NAAs.
Nonroad Mobile:
Fed Phase II Small Eng. Stds.
—Fed Marine Eng. Stds.
—Fed Nonroad Heavy-Duty (≤=50 hp) Engine Stds—Phase 1.
—Fed RFG II (statutory and opt-in areas).
—9.0 RVP maximum elsewhere in OTAG domain.
—Fed Locomotive Stds (not including rebuilds).
—Fed Nonroad Diesel Engine Stds—Phases 2 and 3.
Highway Vehicles:
—National LEV.
—Fed RFG II (statutory and opt-in areas).
—9.0 RVP maximum elsewhere in OTAG domain.
—High Enhanced I/M (serious and above NAAs).
—Low Enhanced I/M for rest of OTR.
—Basic I/M (mandated NAAs).
—Clean Fuel Fleets (mandated NAAs).
—On-board vapor recovery.
—HDV 2 gm std.
Rate of Progress Requirements:
—Effectively, ROP through 1999.

Note that area and mobile source emissions were held constant at Base Case levels in all scenarios. The Base Case emissions for EGUs were obtained from simulations of IPM which projected 1996 electric generation to 2007 based on economic assumptions, unit specific capacity, and the requirements in Title I and Title IV of the CAA. The Base Case emissions that were modeled for the EGU sector are 4 percent higher than the final Base Case emissions for this sector. The EGU emissions estimates for each of the control scenarios in Table IV–1 were also derived using the IPM. Table IV–3 summarizes the emissions reductions provided by the control scenarios compared to the Base Case. The development of emissions data for air quality modeling is further described in the Air Quality Modeling TSD.

TABLE IV–3.—SUMMARY OF NO_X EMISSIONS REDUCTIONS

Region [1]	0.25	0.20	0.15t	0.12	0.15nt
Percent Reduction in Point Source NO_X Emissions From 2007 SIP Call Base Case					
Northeast	29	39	49	52	46
Midwest	40	51	59	65	58
Southeast	35	49	54	61	56
SIP Call [2]	37	48	57	62	57
Percent Reduction in Total NO_X Emissions From 2007 SIP Call Base Case					
Northeast	13	18	22	24	21
Midwest	22	28	33	36	32
Southeast	19	26	29	32	30
SIP Call [2]	20	26	30	33	30

[1] The Northeast includes Connecticut, Delaware, District of Columbia, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Rhode Island; the Midwest includes Illinois, Indiana, Kentucky, Michigan, Missouri Ohio, West Virginia, and Wisconsin; the Southeast includes Alabama, Georgia, North Carolina South Carolina, Tennessee and Virginia.

[2] ''SIP Call'' includes the total percent reduction over all 23 jurisdictions subject to budgets as part of this notice.

3. Modeling Results

The EPA applied UAM–V for each of the four OTAG episodes to simulate ozone concentrations for the Base Case and each scenario. The results for the uniform regionwide scenarios are presented first. This is followed by the results comparing interstate and intrastate trading. The results for the assessment of overall downwind benefits of the budgets applied in upwind States is presented last.

The analysis of model predictions focused 1-hour daily maximum values and 8-hour daily maximum values predicted for all 4 episodes. The rationale for analyzing the model predictions in this way is discussed in Section II.C. Each of the control scenarios was evaluated using the four ''metrics'' listed in Table IV–4. Note that the model predictions used in calculating the metrics were restricted to those 1-hour values >=125 ppb and 8-hour values >=85. Model predictions less than these concentrations were not included in the analysis.

TABLE IV–4.—AIR QUALITY METRICS

Metric 1: Exceedances	The number of values above the concentration level of NAAQS.[1]
Metric 2: Ozone Reduced-ppb	The magnitude and frequency of the ''ppb'' reductions in ozone.
Metric 3: Total ppb Reduced	The total ''ppb'' reduced by a given scenario, not including that portion of the reduction that occurs below the level of the NAAQS.
Metric 4: Population-Weighted Total ppb Reduced.	The same as Metric 3, except that the ozone reductions are weighted by the population in the grid cell in which the reductions occur.

[1] 1-hour values >=125 ppb; 8-hour values >=85 ppb.

A full description of these metrics and the procedures for selecting ''nonattainment'' receptors for calculating the metrics can be found in the Air Quality Modeling TSD. In brief, ''nonattainment'' receptors for the 1-hour analysis include those grid cells that (a) are associated with counties designated as nonattainment for the 1-hour NAAQS and (b) have 1-hour Base Case model predictions >=125 ppb. These grid cells are referred to as ''designated plus modeled'' nonattainment receptors. Using these receptors, the metrics were calculated for each 1-hour nonattainment area as well as for each State. To calculate the metrics by State, the ''nonattainment'' receptors in that State were pooled together.

For the 8-hour analysis, ''nonattainment'' receptors include those grid cells that (a) are associated with counties currently violating the 8-hour NAAQS and (b) have 8-hour Base Case model predictions >=85 ppb. These grid cells are referred to as ''violating plus modeled'' nonattainment receptors. The metrics were calculated on a State-by-State basis for the 8-hour analyses.

In general, the four metrics lead to similar overall conclusions. The results for the full set of receptor areas (i.e., ''designated plus modeled'' for the 1-hour NAAQS and ''violating plus modeled'' for the 8-hour NAAQS) are provided in the Air Quality Modeling TSD for all four metrics. In this preamble, Metrics 1 and 3 are presented to illustrate the results.

a. Impacts of Alternative Controls. The impacts on ozone concentrations of the 0.15t scenario and each of the alternative scenarios are provided by region (i.e., Midwest, Southeast, and Northeast) in Tables IV–5 and IV–6 for Metrics 1 and 3, respectively. The complete set of data for individual States and 1-hour nonattainment areas is provided in the Air Quality Modeling TSD. Table IV–5 shows the percent reduction in the number of exceedances across all four episodes between each control scenario and the Base Case. Table IV–6 shows the percent reduction in total ozone above the NAAQS provided by each scenario, compared to the total ozone above the NAAQS in the Base Case.

TABLE IV–5.—RESULTS FOR METRIC 1: NUMBER OF EXCEEDANCES

	0.25	0.20	0.15t	0.12	0.15nt
Percent Reduction in the Number of Exceedances 1-Hour Daily Maximum >=125 ppb					
Midwest	25	32	38	43	38
Southeast	23	33	34	40	36
Northeast	24	31	36	39	36
SIP Call Total	24	31	36	40	37
Percent Reduction in the Number of Exceedances 8-Hour Daily Maximum >=85 ppb					
Midwest	35	44	50	54	49
Southeast	30	40	46	51	48
Northeast	26	34	41	44	41
SIP Call Total	30	39	45	49	45

TABLE IV–6.—RESULTS FOR METRIC 3: TOTAL ''PPB'' REDUCED

	0.25	0.20	0.15t	0.12	0.15nt
Total ''ppb'' Reduced Compared to the Total ''ppb'' Above NAAQS in Base Case [1] 1-Hour Daily Maximum >=125 ppb					
Midwest	31	39	45	49	44
Southeast	27	37	39	44	41
Northeast	25	32	37	40	37
SIP Call Total	27	35	40	43	40
Total ''ppb'' Reduced Compared to the Total ''ppb'' Above NAAQS in Base Case 8-Hour Daily Maximum >=85 ppb					
Midwest	35	42	48	52	47
Southeast	33	44	49	53	50
Northeast	28	37	43	46	43
SIP Call Total	31	40	46	50	46

[1] The values in this table were calculated by dividing the Total ''ppb'' Reduced in the control scenario by the Total ''ppb'' above the NAAQS in the Base Case. These values represent the percent of total ozone above the NAAQS in the Base Case that is reduced by the control scenario.

The results indicate that the 0.15t scenario provides substantial reductions in both 1-hour and 8-hour ozone concentrations in all three regions.

In the Midwest the 0.15t scenario provides a 38 percent reduction in 1-hour exceedances and a 45 percent reduction in ''total ozone'' >=125 ppb. The regionwide Midwest reductions in 8-hour exceedances and ''total ozone'' >=85 ppb are 45 percent and 50 percent, respectively. Considering individual 1-hour nonattainment areas in this region, the reduction in exceedances due to the 0.15t controls are 36 percent over Lake Michigan,[61] 73 percent in Southwest Michigan, and 54 percent in Louisville. The corresponding reductions in ''total ozone'' >=125 ppb are 44 percent over Lake Michigan, 81 percent in southwest Michigan, and 64 percent in Louisville. The results for other areas are contained in the Air Quality Modeling TSD.

In the Southeast, 1-hour exceedances are reduced by 39 percent and the ''total ozone'' >=125 ppb by 34 percent. Considering individual nonattainment areas in the Southeast, the 0.15t scenario provides a 36 percent reduction in 1-hour exceedances in Atlanta and a 39 percent reduction in exceedances in Birmingham. The reduction in ''total ozone'' >=125 ppb is 41 percent in Atlanta and 54 percent in Birmingham. The overall regionwide ozone benefits across the Southeast are also large for the 8-hour NAAQS. For example, the number of 8-hour exceedances in this region is reduced by 46 percent with the 0.15t scenario.

In the Northeast, 0.15t provides a 37 percent reduction in 1-hour exceedances and a 34 percent reduction in ''total ozone'' >=125 pp. For individual nonattainment areas in the Northeast, the reductions in both Metrics 1 and 3 range from approximately 25 percent in Washington, DC up to 100 percent in Pittsburgh. For the serious and severe 1-hour nonattainment areas along the Northeast Corridor from Washington, DC to Boston, the 1-hour reductions vary from city to city, but are generally in the range of 25 percent to 55 percent. The regionwide reductions in 8-hour exceedances and ''total ozone'' >=85 ppb in the Northeast are above 40 percent.

In general, results from the scenarios evaluated demonstrate that the larger the reduction in NO_X emissions, the greater the overall ozone benefit. As indicated in Table IV–5 and IV–6, the 0.25 and 0.20 scenarios generally do not provide the same level of reduction as the 0.15t scenario in any of the three regions, whereas the 0.12 scenario provides additional ozone benefits beyond 0.15t in all three regions. Also, the results indicate that even with the most stringent control option considered, nonattainment problems requiring additional local controls may continue in some areas currently violating the NAAQS.

The impact on ozone reductions of a trading program versus meeting the budgets in each State can be seen by comparing the results for the 0.15t and 0.15nt scenarios. The data in Tables IV–5 and IV–6 indicate that there is no overall loss of ozone benefits for either 1-hour or 8-hour concentrations across the 23 jurisdictions due to trading. On a regional basis, the benefits of interstate and intrastate trading at the 0.15 control level are essentially the same in the Northeast and Midwest and slightly less with interstate trading in the Southeast.

[61] The rationale for analyzing the impacts over Lake Michigan is discussed in Section II.C, Weight of Evidence Determination of Covered States.

As indicated in the summary of comments, several commenters stated that there would be local disbenefits due to the EPA proposal that would outweigh any benefits. The modeling runs discussed here shed light on the issue. Of the four metrics examined by EPA, Metrics 3 and 4 (i.e., ''Total ppb Reduced'' and ''Population-Weighted Total ppb Reduced'') are most appropriate for identifying any net disbenefits because the ozone decreases and any increases (disbenefits) are considered in calculating each of these metrics. The metrics will have negative values for situations in which the total disbenefits are greater than the total benefits. The EPA examined the 1-hour estimates for these metrics for each 1-hour nonattainment area and the 8-hour estimates by State to identify any areas in which the modeling indicated a net disbenefit. The results indicate that the only net disbenefit predicted in any of the scenarios was in Cincinnati for the 1-hour NAAQS. However, these disbenefits occurred only in the 0.25 and 0.20 scenarios. In the 0.15t scenario, there is a net 32 percent benefit in Cincinnati with Metric 3 and a net benefit of 23 percent with Metric 4. There were no net Statewide 8-hour disbenefits in any of the scenarios examined by EPA.

b. Impacts of Upwind Controls on Downwind Nonattainment. The impacts of the budgets applied in upwind States on downwind ozone in the (a) the Northeast, (b) Georgia, and (c) Illinois-Indiana-Wisconsin, were evaluated by comparing the 0.15nt scenario to the three downwind transport assessment scenarios listed in Table IV–1. In each of these three scenarios, EPA modeled the 0.15nt option in one of the downwind areas with the Base Case emissions applied in the rest of the OTAG region.[62] The results of each downwind control run were compared to the Base Case in order to assess the benefits of the controls applied within those areas (i.e., the downwind areas). Similarly, the predictions for the 0.15nt regionwide scenario were compared to the Base Case to estimate the benefits in each area of the downwind plus upwind controls. The benefits of the upwind controls were determined by calculating the difference between the benefits of the downwind controls compared to the benefits of the downwind plus upwind controls. The results are provided in Table IV–7. The following is an example of how the benefits of upwind controls were calculated for Metric 1 (i.e., number of exceedances). In the Northeast, there were 1052 grid-day exceedances of the 1-hour NAAQS predicted in the Base Case scenario. In the downwind control scenario (i.e., 0.15nt applied in the Northeast only), the number of exceedances declined to 827 grid-days which represents a 21 percent reduction in exceedances from the Base Case due to controls in the Northeast. In the downwind plus upwind scenario, the number of 1-hour exceedances declined even further to 670 grid-days which is a 36 percent reduction from the Base Case. Therefore, the upwind controls provide a 15 percent reduction in 1-hour exceedances in the Northeast (i.e., 36 percent versus 21 percent).

For Metric 3 (i.e., Total ''ppb'' Reduced), the impact of upwind controls on downwind ozone was determined using two approaches. The first approach is similar to the procedures followed described above for exceedances. For example, in the Northeast the total ppb >=125 ppb (across all grids and days) in the Base Case was 14,724 ppb. In the downwind control scenario the total ppb reduced by these controls was 3289 ppb which represents a 22 percent reduction (i.e., 3289 ppb divided by 14,724 ppb) in total ppb >=125 ppb. In the downwind plus upwind control scenario, the total ppb reduced was 5500 ppb which represents a 37 percent reduction in total ppb >=125 ppb in the Base Case. Therefore, the upwind controls provide a 15 percent reduction in total ppb >=125 ppb (i.e., 37 percent versus 22 percent). The results for Metric 3 calculated using this first approach are presented in Table IV–7.

A second approach to analyze the benefits of upwind controls using Metric 3 is to determine the fraction or percentage of the total reduction from downwind plus upwind controls that comes from just the upwind controls. This is determined by first subtracting the ppb reduced by downwind controls from the ppb reduced by downwind plus upwind controls. This difference provides an estimate of the portion of the reduction due to upwind controls. Then, the portion of the reduction due to upwind controls is divided by the reduction from downwind plus upwind controls to estimate the percent of reduction due to the upwind controls only. For example, in the Northeast the 1-hour total ppb reduced by the downwind plus upwind controls is 5500 ppb and the total ppb reduced by the downwind controls is 3289 ppb. The difference (2211 ppb) is the estimated amount of reduction due to upwind controls. Thus, in this example, the upwind controls provide 40 percent (i.e., 2211 ppb divided by 5500 ppb) of the total ppb reduction in the downwind plus upwind regionwide scenario. The results for Metric 3 using this second approach for estimating the impacts of upwind controls are provided in Table IV–8.

	1-hour daily max			8-hour daily max		
	DW[1]	DW + UW[1]	UW[1]	DW	DW + UW	UW
Percent Reduction in Exceedances						
Northeast	21	36	15	18	40	22
Lake MI	29	36	7	11	17	6
IL/IN/WI	35	50	15	27	57	30
Atlanta	30	39	9	[2] NA	NA	NA
Georgia[3]	30	39	9	15	27	12
Percent Reduction in Total ''ppb'' Above the NAAQS						
Northeast	22	37	15	23	43	20
Lake MI	39	44	5	20	28	8
IL/IN/WI	17	33	16	32	62	30
Atlanta	37	43	6	NA	NA	NA

[62] As described in the Air Quality Modeling TSD, emissions from the intrastate trading scenario rather than the interstate trading scenario were used for the analysis of upwind controls in order to avoid any potentially confounding effects of small changes in the downwind emissions between the downwind control scenario and the downwind plus upwind control scenario due to interstate trading.

	1-hour daily max			8-hour daily max		
	DW [1]	DW + UW [1]	UW [1]	DW	DW + UW	UW
Georgia	37	43	6	25	35	10

[1] ''DW'' denotes the reductions due to the downwind controls; ''DW + UW'' denotes the reductions due to controls applied regionwide in upwind plus downwind areas; and ''UW'' denotes the incremental additional reduction in exceedances.
[2] NA: The metrics for the 8-hour NAAQS were not calculated for individual 1-hour nonattainment areas.
[3] The 1-hour results for Georgia are the same as for Atlanta because Atlanta is the only 1-hour nonattainment area in that State.

TABLE IV–8.—PERCENT OF THE TOTAL PPB ABOVE THE NAAQS THAT IS REDUCED DUE TO UPWIND CONTROLS

	1-hour daily max (percent)	8-hour daily max (percent)
Northeast	40	48
Lake MI	12	27
IL/IN/WI	49	48
Atlanta	14	NA
Georgia	14	28

In the following discussion of the impacts of upwind controls on ozone in the three downwind areas, the results for Metric 3 focus on the second approach for calculating upwind impacts using this metric since the results based on the first approach are similar to those for Metric 1, as indicated in Table IV–7.

In the Northeast, the upwind controls provide a 15 percent reduction in 1-hour exceedances and a 22 percent reduction in 8-hour exceedances. The results in Table IV–8 indicate that upwind controls provide 40 percent or more of the total ppb reduction from the downwind plus upwind control scenario for both the 1-hour and 8-hour NAAQS. Considering the results for several 1-hour nonattainment areas in the Northeast, the upwind controls reduce the number of 1-hour exceedances by 21 percent in Baltimore, 12 percent in Philadelphia, 12 percent in New York City, 19 percent in Greater Connecticut, and 3 percent in Boston. The percent of the total ppb reduction from the downwind plus upwind controls that is due to the upwind controls alone is 48 percent in Baltimore, 29 percent in Philadelphia, 38 percent in New York City, 47 percent in Connecticut, and 25 percent in Boston. The results for all of the Northeast 1-hour nonattainment areas are provided in the Air Quality Modeling TSD.

The impacts of upwind controls on nonattainment in Georgia were examined using the 0.15nt scenario in Georgia versus the Base Case scenario and the scenario with 0.15nt applied regionwide. The results, as shown in Table IV–7, indicate that the upwind controls are predicted to reduce the number of 1-hour exceedances in Atlanta by 9 percent. Also, in Atlanta, 14 percent of the 1-hour total ppb above the NAAQS reduced by the downwind plus upwind regionwide scenario is due to the controls applied in upwind States. For the 8-hour NAAQS, the upwind controls provide a 12 percent reduction in 8-hour exceedances within the State of Georgia. The upwind controls provide 28 percent of the total ppb reduction in the downwind plus upwind regionwide control scenario.

To assess the benefits in Illinois-Indiana-Wisconsin due to upwind controls, EPA examined the data for the Lake Michigan receptor area and for the three States, combined. The discussion of results focuses on the Lake Michigan receptor area. The data for this area and the three States are provided in Table IV–7. For the Lake Michigan receptor area, there is a 7 percent reduction in 1-hour exceedances and a 6 percent reduction in 8-hour exceedances due to upwind controls. The upwind controls provide 12 percent of the total 1-hour reduction and 27 percent of the total 8-hour reduction that results from the downwind plus upwind regionwide controls. In Illinois, Indiana, and Wisconsin, the reduction in 1-hour and 8-hour exceedances due to upwind controls are larger than over Lake Michigan (i.e., 15 percent and 30 percent for 1-hour and 8-hour exceedances, respectively). The upwind controls provide nearly 50 percent of the total ppb reductions associated with the downwind plus upwind regionwide control scenario for both the 1-hour and 8-hour NAAQS.

Based on the results discussed above, EPA believes that the controls in today's rulemaking applied in upwind areas will reduce the number of 1-hour and 8-hour exceedances in downwind nonattainment areas. The analysis indicates that in downwind areas, a substantial portion of the 1-hour and 8-hour ozone reductions provided by the regionwide application of these controls are due to those controls in upwind areas.

c. Summary of Findings. The EPA has performed an air quality assessment to estimate the ozone benefits of the proposal and several alternative uniform regionwide control levels. In addition, EPA examined the overall benefits in several major downwind nonattainment areas of the application of the proposal in upwind States. The results of EPA's assessment corroborate and extend the findings presented in the SNPR. The major findings are as follows: (1) The NO_X emissions reductions associated with the proposed Statewide budgets are predicted to produce large reductions in (a) 1-hour concentrations >=125 ppb in areas which are currently nonattainment for the 1-hour NAAQS and which would likely continue to have a 1-hour nonattainment problem in the future without the SIP call budget reductions, and (b) 8-hour concentrations >=85 ppb in areas which currently violate the 8-hour NAAQS and which would likely continue to have an 8-hour ozone problem in the future without the SIP call budget reductions.

(2) The more NO_X emissions are reduced, the greater the benefits in reducing ozone concentrations. There does not appear to be any ''leveling off'' of benefits within the range of NO_X reductions associated with EPA's proposal. That is, NO_X reductions at control levels less than EPA's proposal provide fewer air quality benefits than the proposal and NO_X reduction greater than the proposal provide more air quality benefits.

(3) Any disbenefits due to the NO_X reductions associated with the budgets are expected to be very limited compared to the extent of the benefits expected from these budgets.

(4) There are likely to be benefits in major nonattainment areas due to the downwind application of controls in the proposed budgets. Reductions in ozone transport associated with the collective application of the budgets in upwind States are expected to provide substantial ozone benefits in downwind areas, beyond what is provided by the budgets applied in the downwind areas alone. Together, the downwind reductions and transport reductions from upwind controls will provide significant progress toward attainment in major nonattainment areas within the OTAG region. However, even with the most stringent control option considered, nonattainment problems requiring additional local control measures may continue in some areas currently violating the NAAQS.

V. NO_X Control Implementation and Budget Achievement Dates

A. NO_X Control Implementation Date

In the NPR, the EPA proposed to mandate NO_X emissions decreases in each affected State leading to a budget based on reductions to be achieved from both Federal and State measures. The EPA further proposed that the required SIP revisions for achieving the portion of the NO_X reduction from State measures be implemented by no later than September 2002. The EPA also requested comment on a range of compliance dates between September 2002 and September 2004.

The EPA stated that this range of compliance dates is consistent with the requirement for severe 1-hour nonattainment areas to attain the standard no later than 2005 (for severe-15 areas) or 2007 (for severe-17 areas). With respect to the 8-hour ozone standard, EPA stated that the CAA provides for attainment within 5 years of designation as nonattainment, which must occur no later than July 2000, with a possible extension of up to 10 years following designation as nonattainment. The EPA stated that the range of implementation dates—from September 2002 to September 2004—is consistent with the attainment time frames for the 8-hour standard (62 FR 60328–29). For the reasons described in Section III, below, the applicable attainment date for all affected downwind areas is ''as expeditiously as practicable,'' but no later than certain prescribed dates. In many cases, the date for achieving the upwind reductions will make the difference as to when downwind States will attain. Thus, it is appropriate for EPA to require the upwind reductions to be achieved as expeditiously as practicable. Subsection 1., below, analyzes the earliest date feasible for achieving the upwind reductions.

1. Practicability

After reviewing the comments and analyzing the feasibility of implementing the NO_X controls assumed for purposes of developing the State emissions budgets, as well as other measures which States may choose to rely on to meet the rule, the EPA is today determining that the required implementation date must be by no later than May 1, 2003. The Agency received many comments on the feasibility of installing appropriate control technology by 2003, and the succeeding paragraphs address many of the significant comments submitted on this topic.

Some commenters asserted that a compliance deadline of September 2002 is infeasible for completing the installation of the assumed NO_X controls. Some of these commenters argued that there are not enough trained workers, engineering services or materials and equipment to install NO_X controls by the September 2002 deadline. Other commenters expressed concern that utilities will not have sufficient time to install NO_X controls without causing electrical power outages; these commenters stated that such power outages would have adverse impacts on the reliability of the electricity supply. Commenters also expressed concern that retrofitting NO_X controls would require increasing the operation of less efficient units, which would increase compliance costs.

In response to these comments, the Agency has conducted a detailed examination of the feasibility of installing the NO_X controls that EPA assumed in constructing the emissions budgets for the affected States (hereinafter, the ''assumed control strategy''). See the technical support document ''Feasibility of Installing NO_X Control Technologies By May 2003,'' EPA, Office of Atmospheric Programs, September 1998. The Agency's findings are summarized below. Based on these findings, the EPA believes that the compliance date of May 1, 2003 for NO_X controls to be installed to comply with the NO_X SIP call is a feasible and reasonable deadline. The Agency is also providing some compliance flexibility to States for the 2003 and 2004 ozone seasons by establishing State compliance supplement pools as described above in Section III.F.6.

The EPA's projections for the assumed control strategy include post-combustion controls (Selective Catalytic Reduction [SCR] and Selective Noncatalytic Reduction [SNCR]) and combustion controls (e.g., low NO_X burners, overfire air, etc.)

a. Combustion Controls. In general, the implementation of combustion controls should be readily accomplished by May 1, 2003 for the following reasons. First, there is considerable experience with implementing combustion controls. Combustion control retrofits on over 230 utility boilers, accounting for over 75 GWe of capacity under the title IV NO_X program, took place within 4 years (i.e., from 1992 through 1995). Moreover, the combustion retrofits under Phase I of the Ozone Transport Commission's Memorandum of Understanding were completed in the same time frame. As a result of this experience, the sources and permitting agencies are familiar with the installation of combustion controls. This familiarity should result in relatively short time frames for completing technology installations and obtaining relevant permits.

Second, combustion controls are constructed of commonly available materials such as steel, piping, etc., and do not require reagent during operation. Therefore, the EPA does not expect delays due to material shortages to occur at sites implementing these controls.

Third, there are many vendors of combustion control technology. These vendors should have ample capacity to meet the NO_X SIP call needs because they were able to satisfy significant installation needs during the period 1992 through 1995, as mentioned above. Since then these vendors have had relatively few installation needs to fill.

Therefore, it is reasonable to expect that implementation of post-combustion controls, not combustion controls, would determine the schedule for implementing all of the projected NO_X controls.

b. Post-Combustion Controls. Tables V–1 and V–2 present the Agency projections of how many electricity generating units and industrial sources, respectively, would need to be retrofitted with post-combustion NO_X controls under the assumed control strategy.

TABLE. V–1.—ELECTRICITY GENERATING UNITS

NO_X Control	Projected No. of installations
Coal SCR	142
Coal SNCR	482
Oil/gas SNCR	15
Total	639

TABLE. V–2.—NON-ELECTRICITY GENERATING UNITS

NO_X Control	Projected No. of installations
SCR on coal-fired sources	55
SCR on oil/gas-fired sources	225
SCR on other sources	1
Total	281
SNCR on coal-fired sources	195
SNCR on oil/gas-fired sources	0
SNCR on other sources	40
Total	235

There are three basic considerations related to implementation of post-combustion controls (SCR and SNCR) by the compliance date: (1) Availability of materials and labor, (2) the time needed to implement controls at plants with single or multiple retrofit requirements, and (3) the potential for interruptions in power supply resulting from outages needed to complete installations.

The EPA examined each of these considerations. An adequate supply of off-the-shelf hardware (such as steel, piping, nozzles, pumps, soot blowers, fans, and related equipment), reagent (ammonia and urea), and labor would be available to complete implementation of post-combustion controls projected under the assumed control strategy.

However, the catalyst used in the SCR process is not an off-the-shelf item and, therefore, requires additional consideration. Based on the projections shown in the tables above, the EPA estimates that about 54,000 to 90,000 m^3 of catalyst may be needed in SCR installations. The EPA has found that currently the catalyst suppliers can supply about 43,000 to 67,000 m^3 of catalyst per year. However, of this supply about 5,000 to 8,000 m^3 of catalyst per year is needed to meet the requirements of the existing worldwide SCR installations. Based on these estimates, the EPA conservatively concludes that adequate catalyst supply should be available if SCR installations were to occur over a period of two years or more.

In addition, in comments to EPA's proposed NO_X reduction program, the Institute of Clean Air Companies (ICAC) stated that more than sufficient vendor capacity existed to supply retrofit SCR catalyst to the sources that would be controlled by SCR under the assumed control strategy.

Implementation of a NO_X control technology on a combustion unit involves conducting facility engineering review, developing control technology specifications, awarding a procurement contract, obtaining a construction permit, completing control technology design, installation, testing, and obtaining an operating permit. The EPA evaluated the amount of time potentially needed to complete these activities for a single unit retrofit and found that about 21 months would be needed to implement SCR while about 19 months would be needed to implement SNCR.

The EPA examined several particularly complicated implementation efforts to assure an accurate and realistic estimate of the time needed to install SCR and SNCR. The EPA examined the data and determined that the assumed control strategy might lead one plant to choose to install a maximum of 6 SCRs. In another instance, a different plant might choose to install a maximum of 10 SNCRs under the assumed control strategy. The estimated total time needed to complete these installations is 34 months for 6 SCR systems and 24 months for 10 SNCR systems.

Finally, the EPA examined the impact(s) that outages required for connecting NO_X post-combustion controls to EGUs could potentially have on the supply of electricity and on the cost of this rule. The EPA has found that, generally, connections between a NO_X control system and a boiler can be completed in 5 weeks or less. This connection period has been accounted for in both the single and multi-unit implementation times presented in the previous paragraph. On an EGU, the connection would have to be completed during an outage period in which the unit is not operational. The EPA's research reveals that currently, on average, about 5 weeks of planned outage hours are taken every year at an electricity generating unit. Therefore, the EPA expects that connection between a NO_X control system and such a unit would be completed during one of these planned outages.

Results of EPA's analyses reflect that, even if all of the post-combustion controls projected in Table V–1 for the EGUs were to be connected to these units in one single year, no disruption in the supply of electricity would occur. If each of these plants takes the five week outage in a single block of time, no cost increase is expected to occur. However, if a plant divides the five week outage into two or more periods, a cost increase of less than one-half of one percent may be expected. See the technical support document "Feasibility of Installing NO_X Control technologies By May 2003," EPA, Office of Atmospheric Programs, September 1998.

Based on the estimated timelines for implementing NO_X controls at a plant and availability of materials and labor, the EPA estimates that the NO_X controls in the assumed control strategy (which is one available method for achieving the required NO_X reductions in each covered State) could be readily implemented by September 2002, without causing an adverse impact on the electricity supply or on the cost of compliance. The EPA bases this conclusion on its analysis that the most complex and time-consuming implementation effort—one involving 6 SCR systems—would take 34 months, and that all of the controls could be installed within this period without causing any disruptions in the supply of electricity.

Further, the EPA notes that the September 27, 1994 OTC NO_X Memorandum of Understanding (MOU) provides that large utility and nonutility NO_X sources should comply with the Phase III controls by the year 2003. The levels of control in the MOU are 75 percent or 0.15 lb/10^6 btu in the inner and outer zones of the Northeast OTR, levels comparable to the controls assumed in setting the budget for today's rulemaking. Moreover, several States in the Northeast OTR have submitted SIP revisions implementing this level of emissions reductions from NO_X sources in those States by May 1, 2003. This further supports the feasibility of the May 1, 2003 implementation date for these controls.

The EPA has determined that States would have sufficient time to implement other NO_X control measures in lieu of the boiler controls described above. For example, vehicle I/M programs have historically required no more than two years to implement, including the time needed to pass enabling State legislation and to construct the necessary emission testing facilities. The time required to implement measures to reduce VMT depends on the nature of the measure, but many VMT reduction measures require no more than one or two years to implement. State opt-ins to the RFG program have generally required less than one year to implement. Even if the EPA were to determine that supply considerations warranted a delay in implementing the opt-in request, the delay cannot exceed two years.

States can also take advantage of the NO_X-reducing benefits that energy efficiency and renewables projects provide, many of which could be developed in less than three years and incorporated into a SIP. Examples of efficiency/renewables projects that have been accomplished within a 3-year time frame and have resulted in significant NO_X reductions include reducing boiler fuel use by utilizing waste heat, implementing short-term steam trap maintenance and inspection programs, and undertaking building upgrades using EPA's Energy Star Buildings approach.

2. Relationship to SIP Submittal Date

Under this rule, as explained in Section B. below, States are required to submit revised SIPs by September 30, 1999. Commenters have suggested that based on the requirements of this rulemaking, sources in these States would need to begin early planning of compliance strategies before the September 30, 1999 date. The EPA disagrees. The EPA's technical analysis described above indicates that if these sources begin planning and specification of controls by even as late as April 2000, then they would be able to complete control technology implementation by May 1, 2003.

3. Rationale

To assure adequate lead-time for implementation of controls, the EPA has moved the compliance deadline from the proposed date of September 2002 in the NPR to May 1, 2003. Since the ozone seasons in areas in the eastern U.S. end in the fall and begin in the spring, setting the implementation date for May 1, 2003 will provide sources 7–8 additional months for implementing control requirements while not undermining the ability of areas to attain. The additional implementation time will occur during the cooler months of the year, a time when ozone exceedances generally do not occur. Thus, with either the September 2002 implementation date or the May 1, 2003 implementation date, the 2003 ozone season would be the first to benefit from full implementation of the SIP call reductions.

Several commenters contend that EPA does not have the authority to establish the compliance date. Since section 110(a)(2)(D)(i) is silent as to the implementation schedule for measures to prevent significant contribution, the EPA disagrees that the statute prohibits the EPA from establishing an implementation date for control measures that will achieve the reductions established by the SIP call. Thus, the EPA must look to the other provisions in the CAA, the legislative history, and the specific facts of today's rule to determine whether it is reasonable for the Agency to set the implementation date for the control measures. Furthermore, for the reasons provided in this Section, the EPA believes it is necessary to use its general rulemaking authority under section 301(a) to establish the latest date for implementation through a rule in order to ensure that downwind areas attain the standard as expeditiously as practicable and that areas continue to make progress toward attaining the NAAQS. *See NRDC* v. *EPA*, 22 F.3d 1125, 1146–48 (D.C. Cir. 1994).

With respect to the facts of this particular situation, this SIP call entails a complex analysis of the interstate transport of NO_x and ozone and involves 23 jurisdictions. Although the States made significant progress through the OTAG process, they were unable to reach a final resolution on the emission reductions necessary or the schedule to achieve reductions to address upwind emissions. Thus, it would not be reasonable for EPA to leave open the issue of implementation in light of the need for downwind areas to rely on these reductions in order to demonstrate attainment by their attainment dates. See also the discussion in Section II.A.

Furthermore, EPA believes that requiring implementation of the SIP-required upwind controls, and thereby mandating those upwind reductions, by no later than May 1, 2003, is consistent with the purpose and structure of title I of the CAA. Under both section 172(a)(2), which establishes attainment dates for areas designated nonattainment for the 8-hour standard, and section 181(a), which establishes attainment dates for nonattainment areas for the 1-hour standard, areas are required to attain ''as expeditiously as practicable'' but no later than the statutorily-prescribed (for section 181(a)) or EPA-prescribed (for section 172(a)(2)) attainment dates. The implementation date of May 1, 2003 fits with both the more general requirement for areas to attain ''as expeditiously as practicable'' and the latest attainment dates that apply for purposes of the 1-hour standard and that EPA will establish for the 8-hour standard.

The overarching requirement for attainment is that areas attain ''as expeditiously as practicable.'' This requirement was established in the CAA in the 1970 Amendments and has been carried through in both the 1977 and 1990 Amendments. Thus, although Congress has provided outside attainment dates under the 1970, 1977, and 1990 Amendments, States have always been required to attain as expeditiously as practicable. Congress has furthered this concept of ensuring that emission reductions are achieved on an expeditious, yet practicable, schedule through its inclusion of other provisions in the CAA that rely on similar concepts. Most notably, under both subpart 1 and subpart 2 of part D of title I of the CAA, areas are required to make reasonable further progress toward attainment and thus are not allowed to delay implementation of all measures until the attainment year.[63] While the ROP requirements directly apply only to emission reductions that designated nonattainment areas need to achieve to address local violations of the standard, these provisions highlight congressional intent that—at a minimum—reasonably available or practicable measures should not be delayed if such measures are needed to attain the standard by the applicable attainment date. Thus, it is consistent for EPA to require upwind areas to adopt practicable control measures on a schedule that will help to ensure timely attainment of the standard in downwind areas.

In addition, the May 1, 2003 implementation date is consistent with the statutorily-prescribed ''outside'' 1-hour attainment dates for many of the areas that will benefit from the SIP call reductions.

Currently, areas designated nonattainment for the 1-hour standard have attainment dates ranging from 1996 to 2010. For those with attainment dates in the years 1996–1999, EPA is analyzing whether such areas should receive an attainment date extension due to transported emissions or whether such areas should be reclassified, or ''bumped up,'' under section 181(b)(2), to the next higher classification and therefore be subject to additional control requirements and a later attainment

[63] CAA sections 171(1) and 172(c)(2) (requiring that nonattainment area SIPs provide for reductions in emissions that may reasonably be required by the Administrator for the purpose of ensuring attainment of the applicable national ambient air quality standard by the applicable date; 182(b)(1) and (c)(2)(B) (requiring, respectively, 15 percent reductions between 1990 and 1996 and additional 3 percent average reductions per year until the attainment date, unless, among other things, the plan includes ''all measures that can be feasibly implemented in the area, in light of technological achievability'').

date.[64] To the extent that an attainment date extension is appropriate, consistent with the general requirement of the CAA, it should be no later than the date by which the necessary reductions can practicably be achieved. Thus, it is appropriate for EPA to require upwind reductions by May 1, 2003—a date that EPA has determined can be practicably achieved—in order to allow these areas to attain as expeditiously as practicable. Additionally, there are areas with attainment dates of 2005[65] and 2007[66] that will benefit from the reductions upwind States will require in response to the SIP call. The May 1, 2003 compliance date is sensible in light of the requirement for these areas to make reasonable further progress toward attainment under section 182(c)(2)(B) and to attain as expeditiously as practicable but no later than 2005 or 2007.

The implementation date of May 1, 2003 is also consistent with the attainment date scheme for the 8-hour ozone NAAQS. The EPA is required to promulgate designations for areas under the 8-hour ozone NAAQS by July 2000. Pub. L. No. 105–178 section 6103 and CAA section 107(d)(1). In draft guidance EPA made available for comment in August 1998, the EPA indicated that most new areas that violate the 8-hour ozone NAAQS (but not the 1-hour ozone NAAQS) can achieve sufficient emissions reductions to produce one ozone season's clean air quality by the end of 2003 if EPA establishes May 1, 2003 as the compliance date for this rule.[67] The EPA suggested that these areas would also be eligible for an ozone transitional classification, provided they submit a SIP by 2000 (see the August 1998 proposed guidance). Therefore, in the proposed guidance, EPA has indicated that when the Agency reviews and approves ozone transitional area SIPs, the Agency anticipates establishing December 31, 2003 as the attainment date, for planning purposes, for almost all of the transitional areas. The EPA believes that establishing December 31, 2003 as the attainment date for these areas is consistent with the requirement of CAA section 172(a)(2)(A) that ''the attainment date for an area designated nonattainment with respect to a [NAAQS] shall be the date by which attainment can be achieved as expeditiously as practicable, but no later than 5 years from the date of designation.'' The EPA interprets this requirement to mandate that controls, either in the downwind nonattainment area or in upwind areas, should be implemented as expeditiously as practicable, when doing so would accelerate the date of attainment. For the reasons described elsewhere, the EPA believes it is practicable for States to implement the controls mandated under today's rulemaking by May 1, 2003, and that doing so would ensure that areas subject to the 8-hour NAAQS will attain the standard as expeditiously as practicable. Doing so will be consistent with the requirement that downwind nonattainment areas make reasonable further progress toward attainment.

B. Budget Achievement Date

In the NPR, the EPA stated that although it would mandate the full implementation of the required SIP controls by an earlier date, it would require the affected States to demonstrate that they will achieve their NO_X budgets as of the year 2007. The NPR explained that the 2007 date would allow EPA to make use of the substantial technical information collected by OTAG. The OTAG had selected the year 2007, had collected inventory data geared towards this date, and had generated air quality modeling information geared towards this date. The NPR further stated that the EPA had doubts that there would be significant differences in amounts of emissions and impact on ambient air quality between an earlier date and 2007, in light of the fact that during this period, emissions would generally increase somewhat as a result of growth in activities that generate emissions, but would also decrease due to continued application of federally mandated controls.

The EPA continues to believe that 2007 is an appropriate target date for the affected States to use in demonstrating whether their SIP will achieve the required emissions reductions, generally for the same reasons as expressed in the NPR. Based on the 2007 projections, States are expected to achieve their statewide emissions budgets (based on the required emissions reductions achieved by May 1, 2003) by September 30, 2007 which is the end of the ozone season.

Throughout this rulemaking process, the EPA has relied on technical data generated by OTAG geared towards the 2007 date, and it would be an ill-advised use of resources if EPA did not incorporate the emissions inventories and modeling results generated by the multi-stakeholder OTAG process, and instead developed comparable information for an earlier date. Such an effort would be time consuming and resource intensive. Furthermore, no State is disadvantaged by the requirement to demonstrate compliance with the budget later than the requirement to implement SIP controls because States may count both the growth in emissions and the reductions in emissions from Federal measures that would occur in the interim. Finally, the year 2007 is the latest attainment date under the 1-hour NAAQS for areas in States affected by today's rulemaking, i.e., the severe-17 areas of including Chicago, Milwaukee, and New York, so that this date is a sensible target date for affected States to use in projecting whether they will achieve the required emissions reductions.

VI. SIP Criteria and Emissions Reporting Requirements

A. SIP Criteria

The NPR and SNPR discussed SIP revision approval criteria and the schedule for States' submission plans for meeting statewide emission budgets in response to this SIP call under section 110(a)(2)(D). The EPA received a number of comments related to the proposed SIP approval criteria. This section summarizes these comments on key issues and presents EPA responses.

1. Schedule for SIP Revision

In the NPR, EPA proposed that each State must submit a demonstration that it will meet its assigned Statewide emission budget (including adopted rules needed to meet the emission budget) by September 30, 1999.[68] The EPA received numerous comments concerning this proposed timeframe.

Comments: The EPA received many comments on the practicality of allowing States 12 months to submit SIPs in response to this rulemaking. Some commenters articulated that some States anticipate administrative obstacles that could create problems in

[64] See Guidance on Extension of Attainment Dates for Downwind Transport Areas, Memorandum from Richard Wilson, dated July 17, 1998.

[65] Severe-15 areas, such as Baltimore and Philadelphia, as well as any Serious areas that do not receive an attainment date extension and are bumped up due to a failure to attain, will need to attain no later than 2005.

[66] Severe-17 areas, such as New York City, Philadelphia, Chicago and Milwaukee, need to attain the standard no later than 2007.

[67] ''Proposed Implementation Guidance for the Revised Ozone and Particulate Matter (PM) National Ambient Air Quality Standards (NAAQS) and the Regional Haze Program,'' John S. Seitz, Director, Office of Air Quality Planning and Standards, to Regional Office Air Division Directors, August 18, 1998. The guidance has been made available for 30-days public comment through a Federal Register Notice of Availability (63 FR 45060, August 24, 1998). The date of the notice is the official start date for the comment period.

[68] In the NPR, EPA proposed the SIP submittal date to be within 12 months of the date of final promulgation of this rulemaking. Promulgation means signature so long as the rulemaking is made available to the public on the same day.

submitting their SIP revisions by 1999. On the other hand, many commenters expressed concern about extending the SIP submittal deadline to 18 months based on the additional adverse impact that NO_X emissions from upwind areas would have on downwind air quality if the schedule for reductions were extended. Arguing that the States would have ample time to formulate an approvable SIP, these commenters supported a 12-month SIP submission date.

Response: After considering these comments, EPA is requiring that SIP revisions be submitted within 12 months after the date of signature of this final rule. This date is appropriate in light of the fact that States which are subject to today's rulemaking will need to achieve reductions in NO_X emissions by May 1, 2003. Requiring States to submit SIP revisions within the 12-month timeframe will ensure that controls necessary to reduce these emissions will be in place on time.

The Agency believes the health risks associated with ozone pollution require the NO_X SIP call to proceed expeditiously. Delaying the SIP submission date by an additional 6 months would hinder downwind areas' efforts to improve air quality in a timely manner.

Twelve months is adequate time to submit a NO_X reduction SIP. States were involved in the OTAG for 2 years and, during that time, developed lists of feasible NO_X control strategies and compiled information about control strategy costs. This groundwork will assist States in making decisions about their NO_X reduction strategies and should expedite the SIP submittal process. Further, States developed NO_X emission inventories for modeling purposes during the OTAG process. The States, therefore, have the information for the source categories on which to focus. As a result, many elements needed for putting together a NO_X reduction strategy have already moved forward.

Since OTAG concluded in June 1997, the States have had time for internal review of data, and refinement of their emission inventories. This SIP call rulemaking provides EPA's view of a reasonable cost-effective strategy to reduce NO_X in the 23 jurisdictions. The EPA's action provides a good starting point for State NO_X reduction strategies; States can embrace the Agency's approach or use it as a basis for tailoring their own programs. If States elect to participate in EPA's model trading rule, the SIP process will be further simplified because States can adopt the entire package of recommended strategies.

Therefore, under section 110(k)(5) for the 1-hour NAAQS and section 110(a)(1) for the 8-hour NAAQS, a demonstration that each State will meet the assigned Statewide emission budget (including adopted rules needed to meet the emission budget) must be submitted to EPA in its SIP revision.

2. Approvability Criteria

In the NPR, EPA described the elements listed below that States must include in their ozone transport SIP revisions (62 FR 60365).

The EPA proposed that the approvability criteria for transport SIP submissions appear in 40 CFR 51.121. Most of the criteria are substantially identical to those that already apply to attainment SIPs, for example, a description of control measures that the State intends to use.

The SNPR proposed additional SIP approvability criteria for control strategies that will help States meet their NO_X budgets (63 FR 25912–25914). The legal authority for these additional approvability criteria was articulated in the SNPR (63 FR 25913, footnote 5). The EPA received numerous comments related to these additional criteria.

a. Source Categories Subject to Additional Approvability Criteria. In the SNPR, EPA proposed that, if a State should choose to meet this SIP call by regulating NO_X sources (boilers, turbines and combined cycle units) serving electric generators with a nameplate capacity greater than 25 MWe and boilers with a maximum design heat input greater than 250 mmBtu/hr, the State would need to frame these control measures and monitoring requirements as either: (1) Mass emissions limits, (2) emissions rates assuming maximum utilization, or (3) an alternative approach, as described more fully in the next subsection. The EPA solicited comment on the reasonableness of extending these approvability criteria to additional NO_X sources. The EPA explained that the ability to comply with a mass emissions limit using reasonably available technology and to accurately and consistently monitor mass emissions were key factors for coverage by the additional approval criteria.

In the SNPR (63 FR 25923), EPA also outlined criteria for sources to participate in the NO_X Budget Trading Program. The EPA explained that the ability to accurately and consistently monitor NO_X mass emissions was a key factor for participation in the trading program. The EPA proposed that the trading program include the same sources listed above as well as other large steam-producing units (units above 250 mmBtu/hr) which would include combustion turbines or combined cycle systems, as well as boilers that do not serve electrical generators.

The EPA now believes that the SIP approvability criteria should cover all NO_X sources serving electric generators with a nameplate capacity greater than 25 Mwe and all boilers, combustion turbines and combined cycle units with a maximum design heat input greater than 250 mmBtu/hr. The Agency believes this group is appropriate because of the considerations set forth in the SNPR. For example, all of these sources can comply with a mass emissions limit using reasonably available technology and can accurately and consistently monitor mass emissions. In addition, EPA believes that mass emissions limits remain highly cost-effective for these sources, even when future growth is accommodated within the limits. Based on the analyses in the RIA, EPA projects that even if actual growth for this group of sources exceeds EPA's projected growth by over one-third, mass emission limits would remain highly cost-effective according to the criteria used for this rule. Therefore, in this final rule, EPA is requiring that the additional SIP approvability criteria outlined below apply to States that select regulatory requirements covering boilers, turbines and combined cycle units that are greater than 250 mmBtu/hr—regardless of whether they are connected to an electrical generator of any size—or to boilers, turbines and combined cycle units that serve electrical generators greater than 25 Mwe, regardless of the heat input capacity of the unit.

b. Pollution Abatement Requirements. The EPA proposed requiring States that choose to meet their budget through control requirements for such large NO_X sources to express the requirements in one of three ways: (1) In terms of mass emissions, which would limit total emissions from a source or group of sources; (2) in terms of emissions rates that when multiplied by the affected source's maximum operating capacity would meet the tonnage component of the emissions budget for this source or for these sources; or (3) an alternative approach for expressing regulatory requirements, provided the State demonstrates to EPA that its alternative provides assurance equivalent to or greater than option (1) or (2) that seasonal emissions budgets will be attained and maintained.

Comments: Seven commenters generally support the approach of expressing regulatory requirements as mass emissions limitations. One of these commenters does not object to a mass limit provided that the limit covers a time period no shorter than the ozone season, and that sources should be allowed to maintain flexibility within the ozone season. Several commenters generally support a rate-based limit, one of which noted that EPA's own rule-effectiveness studies show that rate-based limits can be very effective. Another commenter opposes the use of mass emission limits and urges EPA not to require monitoring procedures and data generation that are inconsistent with current requirements under the Acid Rain Program (namely the use of an emissions rate limit). Other commenters believe that States, not EPA, should decide the form of the limit. Finally, one commenter recommends both a cap on mass emissions and an emissions rate limitation.

Response: As explained in the SNPR (63 FR 25912), EPA believes that regulatory requirements in the form of a maximum level of mass emissions for a source or group of sources have the greatest likelihood of achieving and maintaining the Statewide NO_X emissions budget. As with the entire SIP call, the new approvability criteria are designed to apply to total emissions throughout the ozone season and are not intended to apply to shorter time periods within the ozone season. This, however, does not limit a State's ability to require emissions limitations for a shorter time period if deemed necessary in a specific ozone attainment plan.

Although several commenters supported using rate-based limits, they did not provide evidence to refute EPA's belief that the proposed criteria would provide superior environmental results over rate-based limits alone. The EPA maintains that the proposed criteria provide the greatest assurance to downwind States that the air emissions from upwind States will be effectively managed over time. Regarding EPA's rule effectiveness studies, they do confirm that rate-based limits can be effective in achieving a specific emissions rate. However, the studies do not address the emissions variations that may take place at the regulated sources due to changes in utilization under rate-based limits, including the potential for significant increases, particularly in light of utility restructuring. Under the proposed criteria, mass emissions from the regulated sources would stay within a fixed tonnage amount despite shifts in utilization of the sources. Finally, EPA does not believe that the rate-based NO_X emissions limits prescribed under title IV of the CAA are relevant to this rulemaking. Since the time of the 1990 CAA amendments, EPA, States, local governments, and the regulated community have all gained considerable experience with regulatory requirements expressed in terms of mass emissions limitations which demonstrates their feasibility and high degree of effectiveness. For these reasons and the reasons described in the SNPR, EPA is including these additional SIP approvability criteria in today's action.

c. Monitoring Requirements. The Agency proposed requiring these large combustion NO_X sources to use continuous emissions monitoring systems (CEMS), and requested comment on requiring the use of the NO_X mass monitoring provisions in 40 CFR part 75 to demonstrate compliance with applicable emissions control requirements.

Comments: Some commenters generally support the use of CEMS for large combustion sources. One commenter noted that while the preamble and the proposed revisions to part 51 would require CEMS on all sources, the requirements set forth in subpart H of part 75 allow for non-CEMS monitoring options for units that are infrequently operated or that have low mass emissions of NO_X.

Response: The EPA believes that programs like the Acid Rain Program and RECLAIM have shown that CEMS can be effectively used on boilers, turbines and combined cycle units to demonstrate compliance with a mass emissions limitation. The Agency also believes that, while CEMS provide more consistent and accurate data, allowing non-CEMS monitoring options for low-emitting or infrequently operated units greatly increases the cost effectiveness of these requirements without significantly jeopardizing the quality of the data used to ensure compliance with the requirements of the SIP call. Therefore, EPA agrees with the commenter that the part 75 provisions allowing non-CEMS monitoring options for low-emitting or infrequently operated units are reasonable. The EPA is requiring the use of the NO_X mass monitoring provisions in 40 CFR part 75 in the final SIP approval criteria.

d. Approvability of Trading Program. In the SNPR, EPA expressed its intent to approve the portion of any State's SIP submission that adopts the model rule, provided: (1) The State has the legal authority to adopt the model rule and implement its responsibilities under the model rule, and (2) the SIP submission accurately reflects the NO_X emissions reductions to be expected from the State's adoption of the model rule (63 FR 25913). The EPA also stated that a State could develop State regulations in accordance with the model rule. In Section VII.C.3 of this preamble, the Agency clarifies the extent to which a State's regulations may deviate from the model rule and still receive streamlined approval. Regulations providing for streamlined approval appear in paragraph (p) of 40 CFR 51.121.

3. Sanctions

In the preamble to the proposed rule, EPA explained the mandatory sanctions process that is established in section 179(a) and (b) of the CAA (62 FR 60368). This process is triggered upon a finding by EPA that a State failed to submit a SIP in response to a SIP call. One sanction—either increased offsets for new or modified major stationary sources or restrictions on highway funding—is imposed 18 months after the finding is made and the second sanction 6 months later. The EPA requested comment on the order in which these two sanctions should be imposed in response to the SIP call. The EPA further requested comment on whether EPA should use its discretion under section 110(m) to expand the geographic scope of the highway funding sanction.

Comment: One commenter specifically commented on the order in which the two sanctions should be imposed. The commenter recommended that the offset sanctions apply first—18 months after the finding—and the restrictions on highway funding apply second—6 months after the offset sanction.

Response: This is the approach that EPA took in its final rule addressing the sequence of mandatory sanctions for State failures to respond to submittals required under part D of title I of the CAA. For the reasons stated in the preamble to that final rule (59 FR 39832), EPA is providing in the final SIP call rule that the offset sanction will apply 18 months after EPA makes a finding and the restrictions on highway funding will apply 6 months after the offset sanction applies.

Comments: Several commenters generally commented that EPA should be fair and equitable in making findings and imposing sanctions. Other commenters suggested that to be fair and equitable—and because the sanctions are an important backstop to ensuring emission reduction are achieved—EPA should apply the same or similar sanctions to upwind attainment areas as to nonattainment areas that do not comply with the SIP call. Recognizing that the highway sanction can apply to attainment areas only under section 110(m), one commenter encouraged EPA to develop a mandatory clock for the imposition of discretionary sanctions. Finally, one commenter stated that the nature and timing of sanctions should reflect a State's particular circumstances; however, this commenter also emphasized the need for parties to know the impact of sanctions ahead of time so that they can effectively react.

Response: The EPA agrees that sanctions are an important backstop and plans to make timely findings where States fail to submit or submit an incomplete or disapprovable SIP in response to the SIP call. The EPA agrees that areas should be treated fairly and plans to ensure that areas with similar circumstances are not treated differently in making findings of failure to submit and incompleteness. However, at this time, EPA is not prepared to determine whether and when it is appropriate to use the discretion provided under section 110(m) in imposing sanctions. The EPA believes it is not appropriate to make a general determination regarding the application of sanctions under section 110(m); rather if circumstances warrant the use of sanctions under section 110(m), EPA may take future rulemaking action to use that authority. Before EPA uses the section 110(m) authority, EPA must go through notice-and-comment rulemaking, which should provide States adequate certainty about EPA's intentions on the use of discretionary sanctions and time to respond to any action that EPA may take.

Comment: One commenter suggested that the timeframes for the imposition of sanctions are too short and will undermine States' efforts to comply with the SIP call. In addition, the commenter states that the imposition of sanctions serves no useful purpose in light of EPA's intent to promulgate a FIP.

Response: The EPA did not propose imposing sanctions more expeditiously than the timeframes mandated by the CAA. If EPA makes a finding of failure to submit or incompleteness shortly after the SIP is due, the State will have 18 months in which to make a submission that EPA determines is complete before the first sanction would be imposed. Thus, the statute provides sufficient additional time for the State to correct the problem before any sanction would apply. Under the statute, sanctions apply independently of EPA's obligation to promulgate a FIP. Congress recognized that the most efficient and effective programs are those operated by the State; thus, the CAA provides for the continued imposition of sanctions as a means to encourage States to adopt a program to replace the FIP.

Comment: One commenter opposes restrictions on highway funding imposed by any highway sanction in nonattainment areas and especially Statewide.

Response: Under section 179(a) and (b), the highway funding sanction is one of two sanctions that must be imposed due to a continuing failure of a State to adopt a SIP program, including a SIP in response to a SIP call. Under section 179(b), the highway funding sanction can only apply in a nonattainment area. However, under the discretionary sanctions provision in section 110(m), EPA may impose the highway funding Statewide. (See 59 FR 1476, 1479–80 for a more detailed discussion.) The EPA would undertake notice-and-comment rulemaking before imposing sanctions beyond the nonattainment area pursuant to section 110(m).

Comments: Finally, several commenters recommended that EPA not sanction serious areas for failing to demonstrate attainment by 1999 where those areas are affected by transported emissions that will not be controlled until after the 1999 attainment date.

Response: The EPA is not addressing in this rulemaking the process for imposing sanctions for areas that fail to submit or submit incomplete or unapprovable attainment demonstrations. The EPA recently issued a policy memorandum explaining how it anticipates addressing transport for serious areas through rulemaking actions on submitted attainment demonstrations. See memorandum from Richard D. Wilson, EPA Acting Assistant Administrator, to EPA Regional Administrators, dated July 16, 1998, ''Extension of Attainment Dates for Downwind Transport Areas.''

In the preamble to the proposed rule, EPA indicated that if an area fails to implement an approved SIP, the Agency can make a finding that triggers the sanctions clock but does not trigger an obligation to promulgate a FIP. Compare sections 179(a)(1) and 110(c)(1). One commenter noted that EPA should take a forceful role in assuring implementation. Implementation of control measures to achieve the reductions required under the NO_X SIP call is crucial in moving all areas to attainment of the ozone standards. The EPA intends to make findings of failure to implement where the circumstances warrant such a finding.

4. FIPs

Comment: The EPA received several comments supporting the approach outlined in the NPR in which EPA would propose a FIP at the same time as taking final action on the SIP call. The comments noted that the FIPs may be necessary to enforce the SIP call budgets and to assure fair treatment of complying States and industry as compared to States that are not responsive to the SIP call. In addition, many comments were submitted urging EPA to delay proposal of FIPs until (1) after the States have had time to respond to the SIP call, (2) the need for the FIP is established, or (3) up to 2 years after the final SIP call.

Response: Also signed today is a separate notice titled ''Federal Implementation Plans to Reduce the Regional Transport of Ozone,'' EPA is proposing FIPs for each of the jurisdictions affected by the final SIP call rulemaking. While EPA will have a non-discretionary duty to promulgate a FIP within 2 years of a finding that a State has failed to submit a complete SIP, EPA agrees with certain commenters that the timing of the FIP proposal should allow for promulgation in time to require NO_X emissions reductions by sources at about the same time in States that comply with the SIP call and States that do not. Under a delayed FIP proposal approach, sources in the non-complying States might experience an unfair competitive advantage over sources in States which elected to reduce their NO_X emissions and reduce interstate transport of ozone and ozone precursors in an earlier timeframe, consistent with the SIP call rulemaking. More importantly, delaying the FIP proposal would potentially delay reductions of ozone pollution and NO_X emissions in any non-complying State which would unnecessarily jeopardize attainment and public health and welfare. Therefore, proposing a FIP today will ensure that EPA can promulgate a FIP very shortly after the time the SIPs are due, in the event of any State's failure to comply with today's final rule.

B. Emissions Reporting Requirements for States

As stated in the November 7, 1997 NPR and the May 11, 1998 SNPR, the EPA believes it is essential that compliance with the regional control strategy be verified. Tracking emissions is the principal mechanism to ensure compliance with the SIP call and to assure the downwind affected States and EPA that the ozone transport problem is being mitigated.[69]

1. Use of Inventory Data

If tracking and periodic reports indicate that a State is not implementing all of its NO_X control measures beginning on May 1, 2003 or is off track to meet its required reductions by September 30, 2007, EPA will work with the State to determine the reasons for noncompliance and what course of remedial action is needed. The EPA will expect the State to submit a plan showing what steps it will take to correct the problems. Noncompliance with the NO_X transport SIP call may lead EPA to make a finding of failure to implement the SIP and potentially to implement sanctions, if the State does not take corrective action within a specified time period.

The EPA will use 2007 data to assess how each State's SIP actually performed in meeting the statewide NO_X emissions budget.

2. Response to Comments

The EPA proposed reporting requirements in the May 11, 1998 SNPR. That proposal elicited several comments during the public comment period. Some of these comments resulted in changes to the final reporting requirements.

Comment: One commenter asked that the EPA review the need for triennial collection of annual (i.e for the full year) emissions data for uncontrolled sources, as compared to collection of only ozone season data for uncontrolled sources.

Response: The EPA has reviewed the need for reporting of full year emissions (as opposed to only ozone season emissions), and has revised the final rule to remove a requirement that full year emissions be reported. In the final rule, only ozone season emissions must be reported in the annual, triennial and 2007 reports. This NO_X SIP call is aimed at controlling transport of emissions during the ozone season and reporting of full year emission for the purposes of this SIP call is not necessary.

Comment: One commenter said that EPA should evaluate the reporting burden to entities other than the 22 States and the District of Columbia. These entities are likely to include owners/operators of facilities that will be required to report emissions data to States as part of this information collection. Another commenter said EPA should address the additional resource burden on States and facilities required to report.

Response: Since the emissions reporting rule does not place requirements directly on any sources but only on the 23 jurisdictions which receive the SIP call, the EPA is under no legal obligation to evaluate the indirect burdens on sources that may result from the promulgation of this rule. However, based on EPA's assumed control strategy, EPA has performed an analysis of costs which could be incurred by facilities if States require facilities analyzed in EPA's assumed control strategy to report information to aid States in complying with the rule. This cost information includes both capital costs for monitoring equipment, such as continuous emission monitors, and labor costs for testing. These costs are included in the RIA for this rule which is located in the docket for the rulemaking (docket no. A–96–56).

Comment: One commenter is concerned that the definition of point and area sources does not coincide with the definition of smaller point sources included in the inventory, nor with the definition of major sources in ozone nonattainment areas where the threshold is either 25 or 50 tons per year. Another commenter stated that the definition of ''point source'' should reach at least down to the 50 ton per year level, if not lower. This commenter also said that, for consistency, EPA should have a single definition of ''point source'' for the purpose of this rule.

Response: All sources with NO_X emissions equal to or greater than 100 tons per year will remain point sources. However, the EPA has revised its definition of point source for this final rule's reporting requirements to allow States the option of specifying a smaller threshold than 100 tons/year of NO_X for defining point source. When a State chooses this option, non-mobile sources smaller than the State-defined threshold would be area sources in that State. This allows States to tailor their definition of point source to maintain consistency with their own current requirements.

In the proposal, the EPA specifically solicited comments on whether the State reporting time for source emissions should be shortened to no later than 6 or 9 months after the end of the calendar year for which the data are collected. This would allow corrective actions, if needed, to be taken prior to the next ozone season. The EPA also solicited comments on whether different reporting schedules should be established for the different source categories, so that the data which can be obtained more readily would be submitted sooner. The EPA has received several comments on these topics, suggesting a variety of reporting times.

Comment: A State recommended that since the performance of electric generating facilities is known promptly, EPA should shorten the reporting time to no later than 4 to 6 months after the end of the ozone season for which the data are collected. The comment did not specify whether this reporting period , which is shorter than the proposed 12 months, would apply only to electric generating facilities or should apply to all NO_X emitting sources. Another State said the point source emissions reporting period can be shortened to 9 months. Other commenters favored a 12 month or more reporting period. Several commenters did not believe that 12 months after the end of the calendar year is a reasonable time to submit reports and suggested periods ranging from 18 to 24 months. Some commenters thought the reporting time for area and mobile sources must be longer than for point sources; one commenter thought the reporting time for all source types should be uniform.

Response: Many of the emissions from large electric generating facilities would be reported directly to EPA more rapidly than 12 months, if States elect to adopt the model trading program; however, the EPA continues to believe that 12 months from the end of the calendar year for which the data is collected is a reasonable time to require a State to report all emissions from all types of sources. This 12 month period is supported by the comments which say that 12 months, or even less in some situations, is a sufficient reporting time. The EPA believes that States can report emissions from area and mobile sources, as well as stationary sources, within the 12 month period. The uniform 12 month reporting period for all source types was chosen to simplify reporting requirements. However, a State has the option of collecting emissions from particular sectors more rapidly if it wishes. Therefore in the final rule, the EPA is requiring that States submit the required annual and triennial emissions inventory reports no later than 12 months after the end of the calendar year for which the data are collected. Because downwind nonattainment areas will be relying on the upwind NO_X reductions to assist them in reaching attainment by the required dates, EPA believes it is important that data be submitted as soon as practicable to verify that the necessary emissions reductions are being achieved. Early reports will allow States to more quickly respond to implementation problems detected by the reports. States should formally notify the appropriate EPA

[69] Legal authority for the reporting requirements was articulated in the supplemental notice of proposed rulemaking (63 FR 25915–6).

Regional Office when making the submittals.

3. Final Rule

After taking into account the comments submitted in response to the May 11, 1998 proposal, EPA today is promulgating emission inventory reporting requirements for States subject to the NO_X SIP call. The regulatory text appears in 40 CFR 51.122, and the main emission reporting requirements are summarized in Table VI–1 below.

TABLE VI–1.—SUMMARY OF NO_X REPORTING REQUIREMENTS

If you own or operate	and	then, your State must report to EPA the source's
A point source	You are not subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season[2] emissions. 1. triennially [3,5]. 2. for 2007[5].
A point source	You are subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season emissions. 1. annually [4]. 2. triennially [5]. 3. for 2007 [5].
An area source	You are not subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season emissions. 1. triennially. 2. for 2007.
An area source	You are subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season emissions. 1. annually [6]. 2. triennially. 3. for 2007.
A mobile source	You are not subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season emissions. 1. triennially. 2. for 2007.
A mobile source	You are subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season emissions. 1. annually [6]. 2. triennially. 3. for 2007.

[1] The EPA considers the State to rely on regulations to achieve the NO_X reductions required if those regulations require reductions beyond those reflected in the base case 2007 inventory.
[2] Ozone season is May 1 through September 30.
[3] Triennial reporting (which is every 3 years) starts with emissions occurring in 2002.
[4] Annual reporting starts with emissions occurring in 2003.
[5] Triennial and 2007 reports for point sources contain additional data elements not required in the annual reports.
[6] The data elements in the annual report for area and mobile sources satisfy the reporting requirements for these source categories for the triennial and 2007 reports. However, the triennial reports start with emissions occurring in the year 2002 and the annual reports start with emissions occurring in the year 2003.

4. Data Elements to be Reported

In addition to reporting the NO_X emissions values shown in Table VI–1, the State must report other critical data necessary to generate and validate these values. This includes data used to identify source categories such as site name, location and (source classification code) SCC codes. It also includes data used to generate the NO_X emissions values such as fuel heat content and activity level. The specific data elements required for each source category are further defined in 40 CFR 51.122.

5. 2007 Report

The EPA is requiring that States submit to EPA for the year 2007 a special onetime statewide NO_X emissions inventory from all NO_X sources (point, area, and mobile) within the State. The data reporting requirements are identical to the reporting requirements for the triennial inventories, and this reporting requirement is being imposed to allow evaluation of whether the budget is met in 2007. This one-time special inventory is necessary because the ordinary 3-year reporting cycle does not fall in the year 2007.

States which must submit the 2007 inventory may project incremental changes in emissions from 2007 to 2008 to allow the 2008 inventory requirement to be more easily met and to reduce the burden on States which must submit full NO_X inventories for consecutive years, i.e., 2007 and 2008.

The EPA received comments saying that EPA should not require the special report in 2007 due to increased resources required but rather should adjust the schedule of the triennial reports so that a triennial report year will fall on 2007. Alternatively, the EPA could eliminate the 2008 triennial report. The EPA has considered these alternatives, but believes that the schedule which was proposed is necessary to maintain consistency with other EPA reporting requirements and is not unnecessarily burdensome.

6. Ozone Season Reporting

The EPA is requiring that the States provide ozone-season (i.e., May 1 through September 30) inventories for the sources for which the State reports annual, triennial and 2007 emissions. The ozone season emissions may be calculated from annual data by prorating emissions from the ozone season by utilization factors that must be reported and that are further defined in 40 CFR 51.122. For the triennial and 2007 reports, ozone season emissions from all NO_X source categories within the State, controlled or uncontrolled, must be reported. The EPA is requiring that each State provide its ozone season calculation method to EPA for approval.

7. Data Reporting Procedures

When submitting a formal NO_X budget emissions report and associated data, the State should formally notify the appropriate EPA Regional Office of its activities. States are required to report emissions data in an electronic format to one of the locations given below. Several options are available for data reporting. The State may choose to continue reporting to the EPA Aerometric Information Retrieval System (AIRS) using the AIRS facility subsystem (AFS) format for point sources. (This option will continue for point sources for some period of time after AIRS is reengineered (before 2002), at which time this choice may be discontinued or modified.) A second option is for the State to convert its emissions data into the Emission Inventory Improvement Program/ Electronic Data Interchange (EIIP/EDI) format. This file can then be made available to any requestor, either using E-mail, floppy disk, or value added network, or can be placed on a file transfer protocol (FTP) site. As a third option, the State may submit its emissions data in a proprietary format based on the EIIP data model. For the last two options, the terms ''submitting'' and ''reporting'' data are defined as either providing the data in the EIIP/EDI format or the EIIP based data model proprietary format to EPA, Office of Air Quality Planning and Standards, Emission Factors and Inventory Group, directly or notifying that group that the data are available in the specified format and at a specific electronic location (e.g., FTP site). A fourth option for annual reporting (not for third year reports) is to have sources submit the data directly to EPA. This option will be available to any source in a State that is both participating in an approved trading program and that has agreed to submit data in this format. The EPA will make both the raw data submitted in this format and summary data available to any State that chooses this option.

For the latest information on data reporting procedures, call the EPA Info Chief help desk at (919) 541–5285 or e-mail to info.chief@epamail.epa.gov.

8. Confidential Data

Emissions data being requested in today's action are not considered confidential by the EPA (See 42 U.S.C. 7414). However, some States may restrict the release of certain types of data, such as process throughput data. Where Federal and State requirements are inconsistent, the EPA Regional Office should be consulted for final reconciliation.

C. Timeline

The reporting requirements fit into the general time line summarized below:

September 30, 1999—Deadline for SIP submissions in response to this SIP call.

2002—The first triennial emissions inventory report must be submitted for ozone season emissions for this year. States must collect emissions inventory information for all NO_X sources in the State. This report must be submitted by December 31, 2003 (i.e., 12 months after the end of the calendar year for which the data are collected.)

May 1, 2003—The SIP measures required to achieve the NO_X reductions must be implemented by this date.

2003—The first annual emissions inventory report must be submitted for certain ozone season NO_X emissions for this year. Specifically, States must collect emissions information regarding all sources for which the State is relying on measures to meet its NO_X budget (''SIP call sources''). This report is due December 31, 2004.

2004—The second annual emissions inventory report must be submitted for ozone season emissions from SIP call sources for this year. This report is due December 31, 2005.

2005—The second triennial report must be submitted for ozone season emissions from all NO_X sources for this year. The report is due December 31, 2006.

2006—The third annual report must be submitted for ozone season emissions from SIP call sources in the State for this year. This report is due December 31, 2007.

2007—The special year 2007 emission inventory report for ozone season emissions from all NO_X sources in the State must be submitted for this year. This report is due December 31, 2008. The EPA will assess whether States have met their budgets in the year 2007.

2008—The third triennial emissions inventory report must be submitted for ozone season emissions for this year. This report is due December 31, 2009.

Annual and triennial reports must continue to be submitted in future years beyond 2008 in order for the EPA to track compliance with the budget or any revisions to the budget that may occur after 2007.

VII. NO_X Budget Trading Program

A. General Background

In the November 7, 1997 proposed rulemaking, EPA offered to develop and administer a multi-state NO_X trading program to assist States in the achievement of their budgets. Today's notice sets forth a model program on which States may choose to base their SIP submittal. The trading program employs a cap on total emissions in order to ensure that emissions reductions under the transport rulemaking are achieved and maintained, while providing the cost effectiveness of a market-based system. States can voluntarily choose to participate in the NO_X Budget Trading Program by adopting the final model rule, which is a fully approvable control strategy for achieving over 90 percent of the emissions reductions required under the transport rulemaking.

B. NO_X Budget Trading Program Rulemaking Overview

Prior to publication of the proposed NO_X Budget Trading Program, EPA held two public workshops to solicit comments and suggestions from States and other stakeholders on a NO_X cap-and-trade program. Over 150 people participated in each of the workshops. To facilitate meaningful comments from these participants, EPA developed papers on critical issues that were made available for review prior to each workshop. These papers discussed major issues relevant to developing a NO_X Budget Trading Rule, delineated options and, in some cases, offered recommendations. The issues associated with each working paper were presented at the workshops, followed by open discussion periods allowing workshop participants to comment and discuss each issue. Input from workshop participants was extremely helpful in drafting the proposed NO_X Budget Trading Program. In addition to input gained from the workshop process, the NO_X Budget Trading Program builds directly upon the Ozone Transport Commission's NO_X Budget Program and recommendations from the OTAG's Trading and Incentives Workgroup. On May 11, 1998, EPA published the proposed NO_X Budget Trading Program as a part of the supplemental notice for the proposed ozone transport rulemaking. The final NO_X Budget Trading Rule published in today's notice reflects changes that have been made in response to comments received on the May 11, 1998 proposal.

C. General Design of NO_X Budget Trading Program

1. Appropriateness of Trading Program

The EPA proposed that a voluntary market-based program be established as one possible means for a State to meet its NO_X emissions reduction obligations under the NO_X SIP call. The vast majority of commenters, including States, industry, and environmental groups, supported a market approach over traditional ''command and control'' mechanisms to fulfill reduction requirements. However, many commenters argued that the proposed State budgets, based on the cost-effectiveness of an emission limit of 0.15 lb/mmBtu for large combustion sources, are too stringent to provide sufficient surplus allowances to support a market. These commenters argued that cost and technological constraints would prevent regulated sources from over-controlling, thus reducing the pool of allowances and the cost savings EPA predicts would accompany trading. However, several other commenters stated that the trading program was the most cost-effective means to reduce emissions and would in fact generate sufficient allowances for trading. These commenters noted that all but the highest emitting coal-fired units can achieve this rate, and that many sources are able to achieve emission limits significantly below 0.15 lb/mmBtu. They also argued that, at least in the early years of the trading program, the growth factors used to determine the budgets will lead to a less stringent emission reduction requirement than 0.15 lb/mmBtu.

The EPA notes that nothing requires a State to impose a 0.15 lb/mmBtu limit on its large combustion sources. The States will select in their SIPs which sources to regulate and the type of regulation to impose in order to achieve their NO_X budgets. The EPA believes that trading for large combustion sources under a budget based on 0.15 lb/mmBtu is a feasible, highly cost-effective means of meeting a State's budget. The Agency believes that 0.15 lb/mmBtu can easily be achieved by gas and oil-fired boilers. In fact, more than 50 percent of gas and oil-fired boilers already operate at NO_X levels below 0.15 lb/mmBtu and should therefore easily be able to generate excess allowances if trading is allowed. The EPA recognizes that for coal-fired boilers to operate at or below a 0.15 lb/mmBtu emission limit, selective catalytic reduction (SCR) will generally be necessary. Under a trading scenario, however, if one coal-fired boiler is able to emit below 0.15 lb/mmBtu by installing SCR, it can provide excess allowance to another coal-fired boiler and obviate the need for that boiler to install SCR. (For further technical justification for the feasibility of 0.15 lb/mmBtu, see Section III.B.2 of this preamble.) In summary, EPA concludes that, should a State elect to control large combustion sources with a budget based on an emission rate of 0.15 lb/mmBtu, ample allowances would exist to sustain a market under the NO_X Budget Trading Program.

Several of the commenters who did not support the trading program proposed by EPA were generally wary of the use of market approaches for environmental regulation, especially in the context of ozone attainment strategies, citing concerns that emissions in existing nonattainment areas may increase under such a program. The EPA, however, believes that a trading program is an appropriate mechanism to achieve the NO_X reductions required under the SIP call. The EPA proposed the trading program in the SNPR based on recommendations from OTAG, experience from the Ozone Transport Commission, and EPA's public workshops held in November and December 1997. This trading program was designed to mitigate transport of ozone and its precursors to facilitate attainment and maintenance of the ozone NAAQS. Analyses in conjunction with the SIP call show that implementation of a trading program with a uniform control level results in no significant changes in the location of emissions reductions than would result from a non-trading scenario (''Supplemental Ozone Transport Rulemaking Regulatory Analysis'', April 1998, page 2–19). The NO_X reductions required by the SIP call will significantly lower background levels of ozone and can be coupled with local measures to achieve further NO_X reductions, as well as VOC reductions, where necessary to reach attainment. States concerned with contribution by local sources in the trading program are free to limit emissions from particular sources by imposing source-specific emission limits where deemed necessary.

2. Alternative Market Mechanisms

The SNPR proposed to establish a model cap-and-trade program for certain large combustion sources. This proposed program employs a cap on total emissions to ensure achievement and maintenance of the emissions reductions required under the NO_X SIP call while providing the flexibility and cost effectiveness of a market-based system. Several commenters supported EPA's recommendation for a cap-and-trade program. Several others complained that EPA's focus on a capped trading program was inappropriate, citing OTAG's recognition that NO_X market systems could also be implemented without an emissions cap. As a result, these commenters felt that EPA could not make a cap a prerequisite to approval of a State trading program. They suggested that EPA recognize that a rate-based program can be part of a viable SIP, perhaps by outlining parameters of an acceptable alternative program or working with OTAG States to develop a rate-based program that would better accommodate future growth. Another issue raised by a few commenters was that the trading program would either conflict with or would ignore existing local or State-based trading programs.

The EPA first reiterates that the model program is voluntary (63 FR 25918). In providing a cap-and-trade program as a streamlined means by which to comply with the NO_X SIP call, EPA does not preclude implementation of other solutions. The purpose of the trading program is to provide a compliance mechanism that capitalizes on a proven means of cost effectively meeting a specific emissions budget that the Agency will assist States in administering.

As OTAG concluded, the procedures for a cap-and-trade program have already been developed and used successfully, whereas procedures for other types of multi-state trading programs have not been developed and implemented to the same degree. Therefore, EPA does not have the same level of experience or established protocols to follow in the design and administration of other types of trading programs. The OTAG did encourage development of provisions to implement other types of trading programs, and EPA recognizes that these alternative trading programs may be appropriate in some circumstances.

However, EPA recommends a cap-and-trade program for purposes of the NO_X SIP call because, by limiting total NO_X emissions to the level determined to address the interstate transport problem, a cap better ensures achievement and maintenance of the environmental goal articulated in the NO_X SIP call. In contrast, under a non-cap trading program, the addition of new sources to the regulated sector or increased utilization of existing sources could increase total emissions above the level determined to address transport, even though a NO_X rate limit is met.

States, however, have the flexibility to respond as they see fit to meet their emissions budgets established under the NO_X SIP call. States are free to pursue other regulatory mechanisms or include other types of trading programs in their SIPs, whether newly created or already existing, on the condition that they meet EPA's SIP approval criteria as delineated for the NO_X SIP call. These criteria mandate that regulatory requirements for boilers, turbines and combined cycle units that are greater than 250 mmBtu or that serve electrical generators that are greater than 25 MWe be expressed in one of three ways: (1) In terms of mass emissions; (2) in terms of emissions rates that when multiplied by the affected sources' maximum operating capacity would meet the tonnage component of the emissions budget for these sources; or (3) an alternative approach for expressing regulatory requirements, provided the State demonstrates, to EPA's satisfaction, that its alternative provides equivalent or greater assurance than options (1) or (2) that seasonal emissions budgets will be attained and maintained. For further information regarding SIP approvability criteria, see Section VI.A.2.b of this preamble.

3. State Adoption of Model Rule

In the SNPR, EPA proposed that States electing to participate in the NO_X Budget Trading Program could either adopt the model rule by reference or develop State regulations in accordance with the model rule. The few commenters on this issue were primarily concerned about lack of guidance by EPA in this area for State adoption of the model rule and the potential for deviation from the model rule in the State-adopted rules. This section clarifies EPA's intent in issuing a model rule and distinguishes between sections of the model rule that State rules must mirror, and those that States may choose to alter or eliminate while maintaining a SIP that is approvable for purposes of joining the NO_X Budget Trading Program.

a. Process for Adoption. One commenter suggested that rather than adopting the NO_X Budget Trading Program, it should be sufficient for each State to include a statement in its SIP declaring that the State will participate in the Federal program, along with a demonstration of the authority for the State to do so. This would leave the details in the Federal rule and avoid differences that could arise through each State adopting its own rule. However, EPA does not have the statutory authority under title I to promulgate a Federal cap-and-trade program to achieve a State's SIP call budget unless the State fails to respond adequately to the SIP call. The EPA understands the commenter's concern regarding differences among State rules to implement the NO_X Budget Trading Program, and intends to ensure consistency as explained in the following Section.

The EPA's intent in issuing a model rule for the NO_X Budget Trading Program is to provide States with a model program that serves as an approvable strategy for achieving more than 90 percent of the required reductions under the NO_X SIP call. States choosing to participate in the program will be responsible for adopting State regulations to support the NO_X Budget Trading Program, and submitting those rules as part of the SIP. As articulated in the proposed rulemaking (63 FR 25920), there are two legal alternatives for a State to use in joining the NO_X Budget Trading Program: incorporate 40 CFR part 96 by reference into the State's regulations, or adopt State regulations that mirror 40 CFR part 96 but for the variations and omissions described below.

b. Model Rule Variations. The EPA would like to clarify the variations and omissions from the model rule that are acceptable in a State rule, to provide States flexibility while still ensuring the environmental results and administrative feasibility of the program. More specifically, EPA will clarify those variations that maintain a State's eligibility for the streamlined SIP approval associated with adoption of the model rule, those changes that will require more extensive review by EPA prior to approval, and those changes that are not acceptable for incorporation into the NO_X Budget Trading Program.

In order for a SIP revision to be approved for State participation in the NO_X Budget Trading Program, on a streamlined basis or otherwise, the State rule should not deviate from the model rule except in the areas of applicability, NO_X allowance allocation methodology, and early reduction credit methodology (all of which are described briefly in the following paragraphs and in more detail in subsequent Sections of today's notice). Deviations from the model rule regarding allocation methodologies and early reduction credit methodologies as defined in this Section do not impact a State's eligibility for streamlined approval of its SIP with respect to the NO_X Budget Trading Program. However, some deviations regarding applicability will require more extensive EPA review, as explained below. Changes to program applicability may render a State's rule ineligible for streamlined approval, though the rule would still be eligible for approval after a more thorough EPA review.

State rules that deviate beyond the applicability, allocation, and early reduction credit flexibility provided in the model rule would not be approvable for inclusion in the NO_X Budget Trading Program. SIPs incorporating a trading program that is not approved for inclusion in the broader NO_X Budget Trading Program may still be acceptable for purposes of achieving some or all of a State's obligations under the NO_X SIP call, provided the SIP criteria outlined in Section VI.A.2.b are met. However, only States participating in the NO_X Budget Trading Program would be included in EPA's tracking systems for NO_X emissions and allowances used to administer the multi-state trading program.

For States participating in the NO_X Budget Trading Program, applicability is one of the three main areas in which the State may deviate from the model rule. State rules need to include an applicability section that at least covers the core sources defined in the model rule, but States may allow additional stationary sources to participate in the trading program. These sources must be able to monitor and report emissions in accordance with the model rule, and identify an individual responsible for fulfilling program requirements to be eligible for inclusion. States have three options to expand applicability and one to limit it, as explained in the following paragraphs.

States may choose to expand applicability either by: (1) Including smaller sources in the core source categories, (2) including additional source categories, or (3) providing individual sources the ability to opt in. Expansion of applicability to smaller core sources will maintain the State's eligibility for streamlined SIP approval with regard to the NO_X Budget Trading Program. Including additional source categories beyond the core sources (e.g., municipal waste combustors), however, will require more careful review by EPA in some cases to ensure that the trading program requirements can be met, and therefore preclude streamlined SIP approval otherwise associated with adoption of the model rule. Regarding individual source opt-ins, States have the discretion to determine whether or not to include this provision in their State rule. The opt-in provision is not a prerequisite to approval of a SIP incorporating the NO_X Budget Trading Program. However, if a State does choose to include provisions for opt-in sources, these provisions must mirror those in the model rule. Providing the provisions do so, the SIP remains eligible for streamlined EPA approval.

States may also choose to limit applicability of the trading program by allowing units with a low federally enforceable NO_X emission limit (e.g. 25 tons per control period) to be exempt from trading program requirements. A State may include this exemption provision as it appears in the model rule to allow these sources not to participate in the trading program, or a State may omit the provision. Neither of these actions will interfere with streamlined SIP approval by EPA, provided the exemption provisions mirror the model rule if included in the State rule.

In terms of allocations, States must include an allocation section in their rule, conform to the timing requirements for submission of allocations to EPA that are described in this preamble, and allocate an amount of allowances that does not exceed their State trading program budget. However, States may allocate NO_X allowances to NO_X budget sources according to whatever methodology they choose. The EPA has included an optional allocation methodology in 40 CFR part 96, but States are free to allocate as they see fit within the bounds specified above, and still receive streamlined SIP approval for purposes of the NO_X Budget Trading Program.

Today's final rule also includes an optional methodology in § 96.55(c) that States may use for issuing early reduction credits from the State compliance supplement pools. However, States may distribute the State compliance supplement pool to sources as they wish in accordance with the requirements set forth in 40 CFR 51.121(e)(3) and still receive streamlined SIP approval for purposes of the NO_X Budget Trading Program.

In summary, a State is eligible for streamlined approval of the portion of their SIP incorporating the NO_X Budget Trading Program if the State adopts all the provisions of the model rule (e.g., banking and monitoring provisions) with variations incorporated only in the manner explained in this Section. Streamlined approval requires that applicability extends only to the core sources, or to core sources and smaller sources within the core source categories and that the opt-in provision and the exemption option for sources with a low federally permitted emission limit, if included, mirror those in the model rule. Regarding allocations, eligibility for streamlined approval extends to those State rules whose allocations do not exceed the State trading program budget and are determined in accordance with the timing requirements delineated in the model rule. A State rule is still eligible for approval, but not streamlined approval, if the applicability determination for the NO_X Budget Trading Program extends beyond the core sources to additional source categories, to allow for the additional review necessary to ensure such an extension of applicability is administratively feasible and environmentally sound. A State rule is also eligible for streamlined approval if it includes methodologies for issuing credit from the State compliance supplement pool in accordance with the provisions in 40 CFR 51.121(e)(3). Differences among States in these areas will provide flexibility while not detracting from the operation or implementation of the multi-state trading program. Therefore, variations as explained in this section are acceptable to EPA with assurance that State rules will be sufficiently consistent. In addition, joint implementation of the program with EPA will ensure that once these consistent rules are established, they will be implemented consistently as well.

Several commenters expressed concern that the lack of prohibitions on State-imposed trading restrictions in conjunction with the model rule would lead to variation between States and cripple the trading program. The EPA agrees with commenters that additional restrictions imposed on the trading program by individual States could increase economic costs without providing significant environmental benefit. Therefore, EPA does not believe that any restrictions on trading are necessary, and does not foresee approving State rules that include trading restrictions in SIPs incorporating the NO_X Budget Trading Program. However, to address local air quality problems, a State participating in the NO_X Budget Trading Program may establish permit limitations for specific sources participating in the trading program. The EPA considers such a limitation appropriate given local air quality concerns and does not consider it a trading restriction, and therefore the incorporation of such limitations will not preclude streamlined SIP approval. These sources would still participate in the NO_X Budget Trading Program and the unconstrained market operating in the program, but could not use allowances to exceed their permit limitation; the source would be held to the permitted limit, regardless of how many allowances it holds for the purposes of the trading program. This topic is discussed in more detail in the next Section.

4. Unrestricted Trading Market

a. Geographic Issues. For the NO_X SIP call, EPA is basing the State budgets on the uniform application of reasonable, cost-effective NO_X control measures for each State determined to contribute significantly to nonattainment in a downwind State. The EPA's analyses show that the collective reductions across the region will produce significant air quality benefits across the region. The development of and justification for the State budgets under the NO_X SIP call is described in Section III, Determination of Budgets. Although the analyses in today's final action demonstrate that the collective emissions for the NO_X SIP call region significantly contribute to nonattainment, the location of particular emissions does impact the effects that the emissions have on other areas within the region. Emissions in some locations may cause greater overall effects than emissions from other locations.

In the SNPR, EPA proposed a single trading program allowing all emissions to be traded on a one-for-one basis without restrictions on trading allowances within the SIP call region. The EPA also solicited comment on whether the trading program should attempt to factor in differential effects of NO_X emissions based on the location of the emissions. Possible options for factoring in the differential effects include defining exchange ratios for trades between areas based on the differential effects of emissions between areas, establishing subregions for trading, and/or prohibiting certain trades (63 FR 25902 at 25919).

The Agency received more than fifty comments on this issue from the regulated community, States, and environmental organizations. A number of commenters did support limiting trading by establishing smaller subregions within the SIP call region or establishing trading ratios based on the idea that there are differential effects of NO_X emissions based on the location of the emissions. However, none of these commenters included a complete proposal with a justification or description for the appropriate subregional boundaries or trading ratios. The majority of commenters on this subject favored unrestricted trading within areas having a uniform level of control. Most commenters supporting unrestricted trading stated that restrictions would result in fewer cost-savings without achieving any additional environmental benefit and would increase the administrative burden of implementing the program. They expressed concern that discounts or other adjustments or restrictions would unnecessarily complicate the trading program, and therefore reduce its effectiveness.

Consistent with the proposal, the final model rule is designed to be a single jurisdiction trading program allowing all emissions to be traded on a one-for-one basis, without restrictions or limitations on trading allowances within the trading area. EPA has used the IPM to evaluate the emissions and cost impacts of alternative regulatory options under the SIP call for the electric power sector. These analyses can be found in the RIA. The model has been used to show the level and location of emissions if the SIP call were implemented under a number of different alternatives including unrestricted trading and command-and-control approaches. The results indicate that significant shifts in the location of emissions reductions would not occur with unrestricted trading compared to where the reductions would occur under command-and-control and intrastate only trading scenarios. Based upon the IPM results and EPA's air quality modeling, EPA has chosen a region-wide trading program allowing all emissions to be traded on a one-for-one basis without trading restrictions. EPA's analyses suggest that the net effect of all the trades is that the net emissions will not significantly shift within the region compared to a command-and-control scenario. For this reason, EPA believes that the need for trading subregions or trading ratios that differ from one-for-one are unsubstantiated for the purposes of this SIP call and the NO_X Budget Trading Program.

Although the location of net emissions is not expected to significantly shift as a result of trading, it is possible that a State may identify a specific location (e.g., major NO_X source adjacent to or within an urban center) where NO_X reductions would be particularly beneficial for ozone mitigation. For these situations, a State may establish a specific permit limitation restricting the amount of NO_X that may be emitted from the source. The source would still be included in the trading program but it would not be allowed to emit above the amount specified in the permit limitation regardless of the number of NO_X allowances it may hold. The source would be allowed to trade the allowances it is unable to use. In this way, States will be able to tailor specific attainment strategies within the framework of the NO_X Budget Trading Program without restricting the trading options for most sources included in the program.

b. Episodic Issues. The EPA also received several comments addressing the episodic nature of ozone formation and whether this should be factored into the design of the trading program. Commenters noted that under the NO_X SIP call, which is designed to reduce total NO_X emissions from May through September of each year, it is still possible that NO_X emissions may be relatively higher during ozone episodes compared with NO_X emissions on other days between May and September. In addition, the effect of a unit of emissions may be higher during ozone episodes. To address this concern, the commenters stated that the trading program should provide incentives or safeguards to ensure that NO_X emissions reductions are achieved specifically during ozone episodes. One commenter asserted that emissions could either be capped during ozone episodes or that the trading program could place a premium on the use of NO_X allowances during ozone episodes. The commenter recommended the latter option. The premium would require that sources surrender NO_X allowances at rates greater than 1-to-1 for each ton of NO_X emitted during the ozone episodes.

Consistent with the NO_X SIP call, the NO_X Budget Trading Program focuses on reducing total NO_X emissions from May to September for the jurisdictions that are identified in the NO_X SIP call and that choose to participate in the trading program. Proposals to address NO_X emissions during specific episodes and in specific nonattainment areas are more closely tied to issues affecting individual attainment plans rather than the goal of the NO_X SIP call which is to reduce transport. It would be very difficult to apply the appropriate premium to the individual sources that contribute NO_X emissions affecting specific ozone episodes. The meteorology and source contribution for each ozone episode is different. And in some cases, NO_X emissions and the resulting ozone may be transported for several days before contributing to an ozone violation.

Provisions designed to ensure that NO_X emissions reductions are achieved specifically during ozone episodes are more likely to be effective in controlling NO_X emissions that are released adjacent to or within locations frequently affected with elevated ozone levels. Where a State identifies such a source, EPA believes specific permit limitations are an appropriate and effective method for controlling the source's emissions. As stated in the previous section, EPA believes that States may use permit limitations to tailor specific attainment strategies within the framework of the NO_X Budget Trading Program without restricting the trading options for most sources included in the program. Furthermore, this provides each State more flexibility in establishing its attainment plan rather than applying one approach to address the episodic nature of ozone throughout the SIP call region. Therefore, EPA has not included additional trading restrictions to address ozone episodes in the design of the final NO_X Budget Trading Program.

D. Applicability

1. Core Sources

In the SNPR, EPA proposed that compliance with the emission limitation requirements of the NO_X Budget Trading Rule, i.e., the requirement to hold sufficient NO_X allowances to cover emissions, apply to a core group of large stationary sources that includes all fossil fuel-fired stationary boilers, combustion turbines, and combined cycle systems (i.e., units) that serve an electrical generator of capacity greater than 25 MWe and to any fossil fuel-fired stationary boilers, combustion turbines, and combined cycle systems not serving a generator that have a heat input capacity greater than 250 mmBtu/hr. A unit was considered fossil fuel-fired if fossil fuels accounted for more than 50 percent of the unit's heat input on an annual basis. The EPA solicited comment on the appropriateness of the categories included in the core group, whether the size cut-offs should be higher or lower for the source categories, and the appropriateness of including other source categories in the core group. Comments on the concept of a core group fell into three broad categories:

• Those who agreed with the core group concept and who generally agreed with EPA's proposed core group definition;

- Those who felt that the core group definition was too limiting; and
- Those who felt that the core group definition was too inclusive.

a. Commenters Who Felt the Core Group Should Not Be Changed. Commenters who supported the concept of a core group generally and the cut-offs proposed by EPA specifically explained that the cut-offs are consistent with the Acid Rain Program and that the use of a core group will minimize inconsistencies that could impede establishment of interstate trading. Commenters also added that the program should provide the flexibility to allow additional sources to opt-in on an individual basis or for States to bring in additional sources on a categorical basis. Some of these commenters added that the timing for bringing in these sources or source categories should be dependent upon the ability of the source or source category to accurately monitor emissions. For some source categories it might be appropriate to bring them in at the start of the program; for others, it might be necessary to wait until their ability to quantify emissions has improved.

Commenters who generally supported the concept of a core group of sources as it was defined in the SNPR did have several specific concerns. One commenter noted that while the SNPR preamble clearly explained that the rule only included fossil-fuel-fired units, the rule itself was not clear on this issue. Another commenter suggested that because the proposed definition differentiated between electrical generating units and non-electrical generating units it excluded sources that should be in the trading program such as cogeneration facilities that consisted of boilers greater than 250 mmBtu/hr that served electric generating units with a rating of less than 25 MWe.

The EPA agrees that the establishment of a core group will help facilitate interstate trading as well as compliance with the emissions budget. If there is not some minimum group of trading participants, sources that are in the program will have less of an opportunity to trade allowances and realize the economic benefits of trading. In addition, by ensuring that most of the emissions from industries covered by the trading program are included in a capped system, the trading program can be simplified because concerns about load shifting to uncapped sources is minimized. The EPA also agrees that making the cut-offs consistent with existing regulatory programs helps to minimize conflicts with existing regulatory programs. The EPA also agrees with both of the concerns raised by the commenters. Therefore the regulatory definition of unit has been clarified to make it clear that a unit must be fossil-fuel fired. The EPA has also added a clarification to the definition of fossil-fuel fired. This clarification is intended to define a baseline period for determining if a unit is fossil-fuel fired. The revised definition states that fossil-fuel fired means the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel comprises more than 50 percent of the annual heat input on a Btu basis. An existing unit is considered fossil-fuel fired if it meets this criterion for any year since 1990 (or if not operating since 1990 during the last year of operation). A new unit is considered fossil-fuel fired if it is projected to meet this criterion or, if after operation begins, it does meet this criterion.

In addition, to address the concern about excluding cogeneration facilities that are greater than 250 mmBtu/hr that serve electric generating units with a rating of less than 25 MWe, the applicability has been changed to include all units greater than 250 mmBtu/hr, regardless of how much electricity they generate.

b. Commenters Who Felt the Core Group Should Be Expanded. Commenters who felt the trading program should be expanded focused on a number of areas. Several commenters argued generally that the program should allow any source to participate if the source can document that emissions reductions have been achieved. A number of commenters mentioned as examples the inclusion of medium-sized and smaller stationary sources in the RECLAIM program. A few commenters argued that the addition of certain sources is needed for consistency with the OTC NO_X Budget Rule. Other commenters opposed the core group concept because they believe that regulation of low-level and local sources in the Northeast is an essential step in solving the ozone problem. Others argued that excluding non-utility sources from the trading program unfairly excludes these sources from least-cost compliance options. Some commenters suggested specific categories of units that should be allowed to, but not required to, participate in the trading program. These included:

(1) Municipal waste combustors;
(2) Internal combustion engines;
(3) Process units;
(4) Units for which the output product is not comparable to other units on which the allocations are based, such as process heaters, hazardous waste incinerators, process vents and nitric acid plants.

The EPA believes that many of the concerns about the core source definition stem from a misunderstanding of its purpose. The core sources definition was intended to indicate the minimum applicability requirements that a State rule would have to include to participate in a larger multi-state program that EPA would help to administer. It was not intended to limit individual States from including more sources (as long as the sources meet certain criteria further explained below) in the larger multi-state program (63 FR 25924). Nor was it intended to prohibit a State (or group of States) from developing its own trading program with a more limited applicability.

If, however, a State or group of States developed a trading program that did not meet the minimum requirements set forth in the model NO^X Budget Trading Program, such as minimum core source applicability, EPA would not participate in the administration of such a trading program. This is because it would not be administratively cost-efficient for EPA to manage multiple trading programs with a variety of applicability and other requirements designed to address the same issue.

The EPA is not expanding the core source group to include any additional sources because EPA believes that this decision is better left to the states. Therefore the model rule will allow a State to expand the applicability of the trading program to include additional stationary sources if the sources meet certain criteria. These criteria include the ability to accurately and consistently monitor and report emissions and the ability to identify a party responsible for ensuring that monitoring and reporting requirements are met, for authorizing allowance transfers and for ensuring compliance. The EPA's rationale for setting these minimum criteria are set forth in the preamble to the SNPR (63 FR 25923). Also, EPA addresses issues specifically related to the monitoring requirements for these sources in Section D.3 of today's preamble.

There are two mechanisms that can be used to include more sources in the program. One is for a State to expand the applicability criteria to include other source categories; the other is to give individual sources the ability to opt-in.

States that choose to expand the applicability criteria can do so (1) by lowering the applicability threshold for source categories that are already part of the core group in order to include smaller sources or (2) by including additional source categories that are not included in the core group. For instance a State in the OTC might choose to lower the applicability cut-off for electrical generating units to 15 MWe to make the program more consistent with the existing OTC NO_X Budget Program. If a State chose to expand the applicability criteria for source categories already included in the core group this would not affect EPA's streamlined approval of the NO_X Budget Trading program component of the State's SIP.

A State might choose to lower the applicability cut-off for sources in the core group to create different applicability cut-offs for new and existing units. This could help to better facilitate integration with a State's new source review program. The EPA took comment on this concept in the SNPR and received comments both for and against this proposal. Commenters who opposed it suggested that it would be a disincentive to replace old units with new cleaner units. Some of these commenters also noted that expanding the applicability cut-off for all units would provide an incentive to replace these older units. Commenters who favored it suggested that it would be an incentive to make new units as clean as possible. The EPA believes that it is appropriate for States to determine how best to handle the issue of small new units.

Another reason to allow smaller sources to opt-in is to simplify monitoring for situations in which a common stack is shared by a number of units, some of which are affected and some which are not. In this situation the owner or operator would have to either install monitors at each of the affected units, or install monitors at the common stack and at all of the non-affected units, so that the emissions from these units could be deducted from the emissions from the affected units. If the owner or operator is allowed to opt-in the nonaffected unit, they will be able to install one set of monitors at the common stack accounting for the emissions from all of the units.

If a State chose to include additional source categories, EPA would have to review the SIP submittal to ensure that those additional source categories met the minimum criteria for monitoring and reporting emissions and for having a responsible official. As further explained in the SNPR (63 FR 25924), EPA would also have to determine if it could successfully administer a regional trading program with the inclusion of these additional source categories.

In the SNPR, EPA proposed developing a list of specific additional source categories beyond the core group which a State could bring into the trading program without affecting EPA's streamlined approval of the trading component of the SIP. While this concept received general support, none of the commenters provided enough specific support to demonstrate that all of the sources in a given source category could meet the criteria to accurately and consistently monitor emissions. These comments are discussed in Section D.3.

The EPA believes that the opportunity for States to expand the applicability to include additional sources addresses concerns about incompatibility with the applicability requirements of existing programs, such as the OTC Trading Program, as well as concerns that an individual State might want to expand the program to address local ozone problems.

The other mechanism that can be used to broaden the applicability of the program is the individual opt-in procedures in subpart I of part 96. These provisions allow a source to opt-in, if it can meet the monitoring and reporting requirements of part 75. The EPA received a number of comments about the monitoring requirements of part 75 as they related to opt-ins. These comments are addressed in Section D.3 of today's preamble.

In the SNPR (62 FR 25940–25942 and 62 FR 25991–25994), EPA proposed that the individual opt-in provisions would only be applicable to fossil-fuel-fired, stationary boilers, combustion turbines, and combined cycle systems smaller than the applicability cut-offs of 25 MWe or 250 mmBtu/hr. The EPA agrees that the RECLAIM program has demonstrated that many combustion sources that are not included in the core applicability criteria can accurately and consistently monitor NO_X mass emissions using CEM (or other alternative protocols for units with low mass emissions) that are very similar to the provisions in subpart H of part 75. Therefore, in today's action EPA is allowing States to expand the opt-in provisions to include any stationary combustion source that emits to a stack and can meet the monitoring and reporting requirements of subpart H of part 75.

States that choose to add other combustion sources that are not part of the core group would also have to address issues related to allocating allowances for those types of sources. Allocation methodologies that may be appropriate for source categories covered in the core group may not be as applicable for other source categories. For instance, as one commenter noted, an output based allocation methodology might not make as much sense for a municipal waste combustor, since the primary purpose of a municipal waste combustor is to combust waste, not to generate usable output.

c. *Commenters Who Felt the Core Group Is Overly Inclusive.* A number of commenters argued that the burdens associated with including certain source categories would outweigh the benefits and that particular types of sources should therefore be excluded from the core group. Many of these commenters stated that individual sources in these groups should be allowed to opt in where there is a net economic benefit to them to participate rather than mandating inclusion of the source category. Specific categories include: non-utility boilers generally; generators of power for on-site use; combustion turbines exempt from Title IV; small cyclone boilers; combustion turbines below 100 MWe; small, particularly municipal, electric generating units (e.g., those under 25 MWe); and units with low potential to emit as defined by enforceable limits (e.g., peaking units with potential to emit less than 100 tons per year).

The EPA does not believe there is a great distinction between similarly sized utility and non-utility boilers. Both categories of boilers are similar in design, have similar control options and have similar control costs. Therefore, EPA is not excluding large non-utility boilers from the trading program. The EPA believes the same arguments that apply to utility and non-utility boilers also apply to generators of power for on-site use and generators of power for resale. In light of the fact that utility restructuring will provide more opportunities for generators of power for on-site use to resell the power they produce in the future, EPA believes that this distinction is even harder to make. Therefore, EPA is not excluding large generators of power for on-site use from the trading program.

In accordance with title IV of the CAA, the Acid Rain Program exempts simple combustion turbines that commenced commercial operation before November 15, 1990. These units were exempted from the Acid Rain Program because the SO_2 emissions from these units were extremely low. The NO_X emissions from these units are potentially higher; therefore, EPA is not adding a specific exemption for these types of units. However, many of these units are small and/or infrequently operated, so their actual NO_X emissions may be quite low; therefore, some of these units may qualify for the alternative compliance options for units with low NO_X mass emissions, explained below. Combustion turbines smaller than 100 MWe are also likely candidates to qualify for the alternative compliance option explained below.

The Acid Rain Program exempts cyclone boilers with a maximum continuous steam flow at 100 percent load of greater than 1060 thousand lb/hr from NO_X control requirements under part 76. These units were exempted because one of the primary criteria in title IV of the CAA for setting emissions limitations under part 76 was comparability of cost with low NO_X emission controls on boilers categorized as group 1 boilers under Title IV (large tangentially fired and dry bottom, wall fired). There is no such criterion in the CAA applicable to this rulemaking. Also, since the emission reductions required by this rulemaking are more substantial than the emission reductions required under part 76 [70], the cost per ton of reducing NO_X emission reductions is correspondingly higher. Therefore, applicability cutoffs that were relevant in the part 76 rulemaking are not relevant in this rulemaking.

In response to the comment that small electrical generators less than 25 MWe should be exempt from the NO_X Budget Trading Program, they were proposed to be exempt and will be exempt under the final model rule. They do still have the option of opting into the program if they choose to do so.

In the SNPR (63 FR 25926), EPA took comment on allowing units with a low federally enforceable NO_X emission limit (e.g. 25 tons per ozone season), that because of their size would be included in the trading program, to be exempt from the requirements of the trading program. In general commenters supported this concept. One commenter who supported the concept also added that it would be important to ensure that there were adequate requirements to assure that the individual sources who took advantage of this option demonstrated compliance with their unit-specific caps. The commenters who disagreed with this option expressed concern that a State's budget could be exceeded if emissions from these units were not accounted for.

Based on the comments received EPA continues to believe that it is appropriate to offer States the option of providing units that are above the applicability threshold but that have a very low potential to emit an alternative compliance option. This option would allow units that meet the requirements described below to be exempt from the requirements to hold allowances, and to comply with quarterly reporting requirements. In order to address the concern that sources must demonstrate compliance with their individual cap, EPA has added specific requirements that sources must meet in order to use this alternative compliance option.

Units that use this option would be required to:

(1) have a federally enforceable permit restricting ozone season emissions to less than 25 tons;

(2) keep on site records demonstrating that the conditions of the permit were met, including restrictions on operating time;

(3) report hours of operation during the ozone season to the permitting authority on an annual basis.

A unit choosing to use this compliance option would be required to determine the appropriate restrictions on its operating time by dividing 25 tons by the unit's maximum potential hourly NO_X mass emissions. The unit's maximum potential hourly NO_X mass emissions would be determined by multiplying the highest default emission rate for any fuel that the unit burned (using the default emission rates, in part 75.19 of this chapter) by the maximum rated hourly heat input of the unit (as defined in part 72 of this chapter).

States would be allowed, but not required, to incorporate this alternative compliance option into their SIPs. The EPA does agree that if a State does incorporate this option into the SIP, it would have to account for the emissions under its budget. Thus a State that chose to use this option would have to either:

(1) Subtract the total amount of potential emissions permitted to be emitted using this approach from the trading portion of the budget before the remaining portion of the trading budget is allocated to the trading participants; or (2) Offset the difference between total amount of potential emissions permitted to be emitted using this approach and the 2007 base year inventory emissions for these same sources with additional reductions outside of the trading portion of the budget.

If States choose not to incorporate this alternative compliance option into their SIPs, or if they choose to incorporate it exactly as it is set forth in the model rule, it will not affect the streamlined approval of the trading rule portion of the SIP. A State may choose to require an alternative means of ensuring that the potential to emit for units utilizing the alternative means of compliance is limited to less than 25 tons, however if a State deviates from the model rule in this way, the SIP will no longer receive streamlined approval.

2. Mobile/Area Sources

The proposed rule did not include mobile or area sources in the trading program, but solicited comment on expanding applicability to include these sources, or to include credits generated by these sources, in the trading program. Mobile and area sources were not included in the proposed trading rule due to EPA's concerns related to ensuring that reductions were real, developing and implementing procedures for monitoring emissions, and identifying responsible parties for the implementation of the program and associated emissions reductions.

The EPA received comment from State and local government, industry and coalitions of industry, and environmental groups regarding the inclusion of mobile and area sources in the program. Comments focused on the following main areas: inclusion or exclusion of mobile and area sources, subcategories of mobile sources for inclusion, and the use of pilot programs to foster innovation.

Some commenters urged EPA to include mobile and area sources with as few restrictions as possible in the trading program, primarily on an opt-in or voluntary basis. These commenters argued that excluding mobile sources would reduce the potential scope and benefits of the trading by placing a large portion of States' NO_X inventory outside the scope of the trading program. They noted that the existence of RECLAIM protocols for mobile and area source credit generation demonstrated that EPA's quantification, verification, and administration concerns were misplaced.

The majority of commenters, however, indicated that mobile sources should not be included at this time and that the model rule should not be delayed to address concerns related to inclusion of these sources. Some commenters argued against ever including mobile and area sources in the program. One State argued that inclusion of mobile and area sources would destroy the integrity of the program since mobile and area source reductions are not necessarily real, verifiable and quantifiable, failing to display a level of certainty comparable to those sources included in the trading program. A few commenters indicated that mobile sources were inherently unsuited to a capped system, since the difficulties of measuring emissions from these sources precludes their inclusion in a budget.

[70] The lowest emission rate required under part 76 is 0.40 lbs/mmBtu.

Several commenters suggested that some categories of mobile sources should be included while other categories should not. Commenters indicated, for example, that it is not feasible to have individual motorists participate in the cap-and-trade program due to the burdens and administrative complexity associated with such a vast number of sources and responsible parties in a trading system. Alternatively, commenters argued that manufacturers, fuel distributors, and fleet owners could be included if they were able to generate surplus emission reductions by going beyond the requirements established by some Federal measures. These commenters specifically cited the low-RVP regulations, the vehicle scrappage guidance, and the locomotive regulations as examples of such Federal measures.

Several commenters who recommended that mobile sources not be included in the program at this time also recommended that EPA sponsor pilot programs in States to study the feasibility of inter-sector trading and to develop mechanisms to address the specific concerns mentioned regarding the inclusion of mobile and area sources. Along similar lines, one industry commenter stated that mobile sources may be appropriate candidates for participation in the trading program only if adequate emission reduction measurement protocols can be developed. Foreseeing this occurrence, some commenters felt that EPA should leave a placeholder in the rule or add a provision that would include mobile and area sources once the mechanisms to address the specific concerns of EPA and others have been developed.

The model trading program that EPA is finalizing today will not include mobile and area sources for the reasons outlined in the SNPR. The EPA concurs with the concerns raised by commenters against the inclusion of mobile and area sources, regarding program integrity, emissions monitoring, and accountability. Most of the proponents of including mobile or area sources listed general reasons for including them such as increasing market efficiency, lowering costs, or simply the existence of RECLAIM protocols to do so. However, these commenters did not provide sufficient information or documentation to support the validity of these assertions, and several acknowledged that the potential for improvement in market efficiency or lower compliance costs was difficult to ascertain. Further, one proponent acknowledged that the RECLAIM protocols are new and not yet extensively utilized.

In fact, a recent audit of the RECLAIM program indicates that the volume of mobile source credits used under the program is very small (only 99 NO_X tons have been converted from mobile source reductions in the last five years). Only 5 requests for conversion of mobile source emission reduction credits to RECLAIM trading credits were approved in 1994, and no further requests had been received as of May 1998. The small amount of credits relative to the significant resource expenditure for the conversion of mobile source credits under the RECLAIM program (i.e., the need for case-by-case review given the variability and complexity of the petitions) suggests that the RECLAIM mobile source protocols and strategy are not yet a cost-effective option for the trading program.

The EPA remains willing to consider adding mobile or area sources to the trading program in the future. Most commenters recommended that the program be opened to mobile or area sources once adequate mechanisms are developed for addressing related concerns. In response to these comments, and those recommending that EPA support pilot programs in States in order to facilitate resolution of the areas of concern for mobile and area sources, EPA will investigate how grant funding may be used for such pilots. Additionally, EPA is pursuing possible ways to incorporate mobile and area source strategies into other trading and incentive programs. Through these efforts, EPA will work with States in finding solutions to adequately address concerns such as emissions variability, difficulty in controlling emissions growth, difficulty in monitoring emissions levels, and difficulty in establishing emissions baselines. Through this process, EPA and States will explore and develop the necessary protocols that could eventually allow the inclusion of mobile and area sources in some capacity in the NO_X Budget Trading Program. Anticipating that the quantification, verification, and administration concerns regarding expansion of the trading program to include mobile and area sources may be sufficiently resolved in the future, EPA is reserving in this rulemaking a section in part 96 for future inclusion of mobile or area sources in the NO_X Budget Trading Program.

The EPA is aware of other concerns on which the Agency did not receive comment, including the adequacy of some of the existing mobile source protocols and the enforcement of mobile source credit generation strategies. These emerging issues, coupled with past experience, and the issues raised by commenters lead EPA to conclude that it is not appropriate to include mobile and area sources in the NO_X Budget Trading Program at this time.

3. Monitoring

For the reasons set forth in the SNPR (63 FR 25938–40), EPA proposed that sources in the NO_X Budget Trading Program use the monitoring methodologies in proposed subpart H of part 75 to quantify their NO_X mass emissions (63 FR 28032). The comments that EPA has received can be classified into three main categories:

- Support for requiring the use of part 75 to demonstrate compliance with the trading program,
- Support for using CEMS on large units, but concerns about using part 75 as the monitoring protocol, and
- Concerns about requiring CEMS.

Some of the commenters concerned about requiring CEMS focused on units of any size that are not subject to the provisions of the Acid Rain Program. Others focused on smaller units.

The EPA proposed revisions to part 75 (63 FR 28032) for a number of reasons, one of which was to add procedures for monitoring NO_X mass emissions (subpart H). These procedures could be used by sources to comply with any State or Federal program requiring measurement and reporting of NO_X mass emissions. In particular, subpart H would be used by sources to meet the monitoring and reporting requirements of the NO_X Budget Trading Rule (part 96) and the monitoring and reporting requirements of the SIP call for (1) combustion units (boilers, turbines and combined cycle units) which serve electric generators greater than 25 MWe and (2) combustion units greater than 250 mmBtu/hr, regardless of whether they serve a generator.

The part 75 revisions also proposed to make a number of other changes that would affect units using part 75 to comply either with the requirements of title IV or the requirements of a NO_X mass emissions program that incorporated or adopted the requirements of part 75. These included a number of minor changes to simplify and streamline the rule to make it more efficient for both affected facilities and EPA, a new excepted monitoring methodology that would reduce monitoring burdens for affected facility units with low mass emissions, new quality assurance requirements based on gaps identified by EPA during evaluation of the initial implementation of part 75, and several minor technical changes to maintain uniformity within part 75 and to clarify various provisions.

The following discussion addresses comments received in the SNPR docket (A–96–56) that are related to the general requirement to monitor emissions, the requirement to monitor emissions using CEMS, and the requirement to monitor using part 75. Although EPA had requested that all comments related to the use of part 75 for monitoring NO_X mass be submitted to the part 75 docket (A–97–35), some comments also dealt with the specific requirements set forth in part 75.

In today's rulemaking, EPA is finalizing sections of part 75 related to monitoring NO_X mass emissions as well as those which address the excepted monitoring methodology for units with low mass emissions of NO_X and SO_2 that combust oil or natural gas. Units using this methodology to comply with the requirements of part 96 would be subject only to the NO_X mass emission requirements and not to the SO_2 mass emission requirements. For a more complete discussion of the NO_X mass monitoring and reporting provisions in part 75, see the Amendments to Part 75 Section below and Appendix A of this preamble. These Sections discuss both the comments received in the part 75 docket as well as the comments received in the SNPR docket that address the specific requirements of part 75.

a. Use of Part 75 to Ensure Compliance with the NO_X Budget Trading Program. Several commenters supported the idea of requiring all sources in the trading program to meet the monitoring provisions of part 75. Some of these commenters noted that part 75 provides the consistent and accurate monitoring requirements necessary to ensure the integrity of a cap and trade program. They also noted that the proposed revisions offered the flexibility needed for sources to be able to reasonably comply.

Several commenters supported the concept of trying to consolidate the monitoring and reporting requirements for units in the NO_X Budget Trading Program already subject to part 75 under the Acid Rain Program.

Response: The EPA agrees that accurate and consistent data are important to ensure the integrity of a trading program and that the protocols in part 75 provide for such accurate and consistent data from stationary combustion sources. Today's final model rule would require all sources in the trading program (including sources currently subject to part 75) to use the monitoring and reporting procedures set forth in subpart H of part 75.

b. Use of CEMS on Large Units. A number of commenters expressed support for the requirement that large units should use CEMS to quantify NO_X mass emissions. Many of these commenters did, however, have concerns about using part 75 as the basis for this monitoring. Some of these commenters elaborated that part 75 was specifically developed for utility units and that it might not be applicable to other types of units. Commenters also expressed concerns about costs associated with upgrading existing CEM systems to meet the part 75 requirements. The main alternatives they suggested were either using existing State monitoring and reporting requirements or allowing States the discretion to create or approve new monitoring and reporting requirements.

Response: For reasons set forth in the preamble to the SNPR, EPA believes that the use of CEMS, in general, and the protocols in part 75, more specifically, are the most effective way to ensure that NO_X mass emissions from large combustion sources are quantified in an accurate and consistent manner from source to source and are reported in a consistent and cost-efficient way. This is important to maintain the integrity and efficiency of the trading system.

The EPA believes that the protocols in part 75 can appropriately be applied to all of the core sources (fossil fuel-fired electric generating units and industrial boilers). The issues associated with monitoring NO_X mass emissions from a stack attached to a boiler, turbine, or combined cycle unit are the same regardless of whether that boiler, turbine, or combined cycle unit is owned or operated by a utility, by an independent power producer, or by a manufacturer. The EPA does acknowledge that there may be additional issues associated with monitoring NO_X mass from units such as process heaters or cement kilns.

The RECLAIM program uses very similar protocols to the ones in part 75 to quantify NO_X mass emissions. Both RECLAIM and part 75 require the use of NO_X CEMS and flow CEMS to quantify NO_X mass emissions from large sources combusting solid fuel. Both RECLAIM and part 75 also offer large oil and gas units an additional option for monitoring. This option involves the use of a fuel flowmeter and fuel sampling and analysis. The RECLAIM program requires monitoring of source categories that are in the NO_X Budget Trading Program core group, such as boilers and turbines, but also requires monitoring of source categories that are not in the core group, such as process heaters and cement kilns.

RECLAIM needed to establish a standing working group to resolve issues related to monitoring NO_X mass from such a wide range of source categories (See South Coast Air Quality Management District, RECLAIM Program Three Year Audit and Progress Report, May 8, 1998). EPA does not believe that the problems that RECLAIM has had with monitoring are related to the protocols that program uses. Rather, EPA believes these problems are due to the limited experience that both States and sources have with monitoring such a wide range of source categories.

The EPA believes that regardless of what protocols are used, if States opt to bring additional source categories into the trading program, issues related to monitoring at specific source categories will arise. These issues will need to be resolved, thus improving State and EPA experience with those source categories. If a State wants to include additional sources beyond those included in the core group, then EPA would resolve issues through the initial certification process for opt-in units. The EPA will also provide additional guidance on specific source categories, sharing the experiences gained with individual opt-in units.

Using one basic set of protocols will make it easier for states, sources and EPA to work together while gaining more experience with these sources and resolving the issues in a cooperative and consistent manner.

The EPA believes that the most significant costs associated with upgrading from an existing NO_X emission rate monitoring system to a part 75 NO_X mass monitoring system are associated with the need to monitor NO_X mass and would be incurred regardless of the specific monitoring protocol that was required. Many existing CEM rules other than part 75 require sources to monitor NO_X emission rate (in lbs/mmBtu) or NO_X concentration corrected for oxygen (in ppm)(e.g. monitoring requirements under Subpart D, Da, Db of part 60). In order to meet these requirements, a NO_X monitoring system must consist of a NO_X concentration CEM, a diluent CEM and a data acquisition and handling system (DAHS). The DAHS is the part of the system that collects raw monitor data, performs calculations, and generates reports.

In order to upgrade an existing system so that it can monitor NO_X mass, a source must install a flow CEMS, if it burns solid fuels, or must install either a flow CEMS or a fuel flow meter if it burns a homogeneous oil or gas. In addition, the source would have to upgrade its DAHS to reflect the reporting of NO_X mass rather than NO_X emission rate or NO_X concentration. These costs must be incurred, regardless of the protocol that a source used to monitor NO_X mass.

The EPA believes that a single monitoring and reporting protocol for the NO_X Budget Trading Program will keep the costs of upgrading systems to a minimum. This is because equipment vendors will be able to create standardized systems that will be applicable to all sources in the program, rather than having to create many different State- and source-specific systems. A single monitoring and reporting protocol will also help ensure a level playing field for all affected sources.

For these reasons, part 96 requires all large units to monitor NO_X mass emissions using CEMS in accordance with part 75. However, as explained below, part 75 does offer various monitoring options for low-emitting or infrequently operated oil- and gas-fired units, in addition to CEMS.

c. Commenters Who Do Not Believe That CEMS Are Necessary. Some commenters expressed concerns about requiring CEMS on any unit that does not currently have a CEMS monitoring requirement. Suggested alternatives included the use of stack test data and emission factors. Some commenters also suggested the testing and monitoring provisions of a source's title V permit.

Response: For large sources, EPA does not believe that stack test data and emission factors provide the consistent and accurate data needed to facilitate a trading program. Stack test data provide a one-time assessment of a source's emission rate. Emission factors at best are based on a series of stack tests at similar units. A unit's actual emission rate may fluctuate greatly over time due to factors such as the way the unit and/or its associated control equipment is operated and maintained and the quality of fuel that the unit burns. An emission factor or stack test will often not be representative of that unit's actual normal emissions. Continuous monitoring of actual emissions will ensure that fluctuations in emission rates are accounted for. Because CEMS provide continuous monitoring, they can also indicate when emission control equipment is malfunctioning, thus, helping to ensure that the owners of units continue to properly operate and maintain any installed emission control equipment.

Title V permits incorporate all of the monitoring requirements to which a source is subject in order to demonstrate compliance with its current regulatory requirements. In addition, where a source is not subject to any other monitoring requirements, it sets forth minimum monitoring requirements. In many cases the current regulatory requirements do not require compliance with a mass emissions limitation. Therefore, the monitoring requirements are not designed to demonstrate compliance with a mass emission limitation.

Even when a source may have monitoring requirements designed to demonstrate compliance with a mass emissions limitation, the stringency of these requirements often varies from source to source and from State to State. These variations in turn lead to inconsistencies in sources' accounting of mass emissions. This both creates an uneven playing field for sources and undermines the integrity of the trading program.

The EPA believes that it is necessary for all sources in the trading program to be subject to accurate and consistent monitoring requirements designed to demonstrate compliance with a mass emission limitation. This will ensure compliance with the requirements of the SIP Call and will ensure the integrity of the trading program.

The EPA does believe that it is appropriate to provide lower cost monitoring options for units with low NO_X mass emissions. Part 75 allows non-CEMS alternatives to quantify NO_X mass emissions for gas and oil fired units that have low NO_X mass emissions and/or that operate infrequently.

In contrast, EPA does not believe that the types of protocols set forth in the Compliance Assurance Monitoring (CAM) rule, part 64, are appropriate for a trading program because they were not designed to quantify mass emissions. The preamble to the CAM rule further elaborates why these protocols are not appropriate for a trading program (62 FR 54915, 54916, 54922).

The EPA believes that the types of protocols in RECLAIM and the Ozone Transport Commission's NO_X Budget Trading Program (''OTC Program'') are more appropriate for a trading program because they were specifically designed to quantify NO_X mass emissions. The EPA also believes that the flexible monitoring options offered by part 75 are consistent with the type of flexibilities offered in RECLAIM and the OTC Program. RECLAIM requires CEMS on all units that burn solid fuels and all units that emit more than 10 tons per year, regardless of the type of fuel they burn.. The OTC Program requires CEMS on all units that burn solid fuels and all units that do not qualify as peaking units, that are larger than 250 mmBtu/hr or that serve generators greater than 25 MW. Like RECLAIM and the OTC Program, part 75 requires CEMS on all units that burn solid fuel. Part 75 also requires the use of CEMS on oil and gas fired units that emit more than 50 tons of NO_X annually (or for units that only report during the ozone season, 25 tons of NO_X during the ozone season), or that don't qualify as peaking units. In both the OTC Program and part 75, a peaking unit is defined as a unit that has a capacity factor of no more than 10 percent per year averaged over a three year period and no more than 20 percent in any one year.

The EPA believes that these exceptions in part 75 provide cost-effective monitoring alternatives to CEMs for small, low mass emitting, or infrequently used units, and therefore, it is appropriate that part 96 require all units to use part 75.

d. Issues Related to Monitoring and Reporting Needed to Support a Heat Input Allocation Methodology. For monitoring and reporting NO_X mass emissions, subpart H of part 75 requires the use a NO_X concentration CEM and a flow CEM. Since the methodology does not require the use of heat input, EPA would not require sources to monitor or report heat input or NO_X emission rate for a NO_X mass emission reduction program. If a State elects to use a periodically updating allocation methodology that utilizes heat input, it may need to require sources using this methodology to monitor and report heat input also.

e. Amendments to Part 75 (1) Summary of Part 75 Rulemaking. Title IV of the CAA requires the EPA to promulgate regulations for continuous emissions monitoring (CEM). On January 11, 1993, final rules (40 CFR part 75) were published (58 FR 3590). Technical corrections were published on June 23, 1993 (58 FR 34126) and July 30, 1993 (58 FR 40746). A notice of direct final rulemaking and a notice of interim final rulemaking making further changes to the regulations were published on May 17, 1995 (60 FR 26510 and 60 FR 26560, respectively). Subsequently, on November 20, 1996, a final rule was published in response to public comments received on the direct final and interim rules (61 FR 59142).

The EPA proposed further revisions to part 75 on May 21, 1998 (63 FR 28032). These revisions included a new subpart H which sets forth procedures for monitoring NO_X mass emissions, which could be used by sources to comply with any State or Federal program requiring measurement of NO_X mass emissions, including the requirements of the NO_X Budget Trading Rule (part 96). The May 21, 1998 proposed revisions also proposed to make a number of other changes that would affect units that were using part 75 to comply either with the requirements of title IV or the requirements of a NO_X mass trading program under title I that incorporated or adopted the requirements of part 75. These included a number of minor changes to simplify and streamline the rule to make it more efficient for both affected facilities and EPA; a new excepted monitoring methodology that would reduce monitoring burdens for affected facility units with low mass emissions; and new quality assurance requirements to fill in gaps identified by EPA during evaluation of the initial implementation of Part 75.

(2) Schedule For Part 75 Final Rulemaking. The comment period for the proposed revisions to part 75 ended on July 20, 1998. EPA anticipates completing rulemaking on all of proposed revisions to part 75 by the end of the year. However, because the revisions to subpart H of part 75 relating to the monitoring and reporting of NO_X mass emissions are integral requirements of the SIP Call, EPA is finalizing most of the requirements of subpart H of part 75 with today's action.

The EPA is also finalizing a new excepted monitoring methodology for units that combust natural gas and or fuel oil with low mass emissions of NO_X and SO_2. These provisions are being finalized because they are one of the methodologies that certain gas and oil units can use to quantify NO_X mass under the new subpart H of part 75.

The EPA is not finalizing the rest of the proposed revisions to Part 75 at this time because EPA is still evaluating the comments received on the proposed rulemaking. Many of these remaining provisions will be applicable to any unit that must use the requirements of part 75 in order to meet the requirements of title IV or to meet the requirements of a State or Federal NO_X reduction program that adopts the part 75 requirements. For example, the proposed revisions would allow a unit with CEMS to be exempt from the requirement to perform a linearity test in any quarter that the combustion unit for which the CEMs is installed operates for less than 168 hours. If EPA ultimately finalizes this proposed flexibility, it will become available both to units using part 75 to comply with title IV and to units using it to comply with the part 96 model trading rule. As another example, EPA proposed quality assurance requirements for moisture monitors that would be needed if pollutant concentration (NO_X, SO_2 or CO_2) were measured on a dry basis and needed to be converted to a wet basis so that mass emissions could be determined using a stack flow meter. If EPA ultimately finalizes this proposed requirement it will affect both units using part 75 to comply with title IV and units using it to comply with part 96 (or a State or Federal NO_X mass reduction program that adopts part 75).

The EPA is also not yet finalizing the recordkeeping and reporting requirements associated with either the NO_X mass monitoring provisions in subpart H or the low mass emitter monitoring methodology because EPA believes that these reporting requirements should be coordinated with any changes in the reporting requirements that result from the finalization of the rest of proposed revisions to part 75.

Therefore, EPA has closed the part 75 docket (A–97–35, with respect to the provisions that are being finalized in today's rulemaking: section 75.19, a new excepted methodology for estimating emissions for units with low mass emissions; and subpart H, a new subpart setting forth provisions for monitoring, recording and reporting NO_X mass emissions, except where EPA has reserved final action on related aspects of these provisions. EPA has not closed the docket with respect to the other provisions that were the subject of EPA's, May 21, 1998 proposal (63 FR 28032).

(3) Summary of Major Differences Between Proposed and Final Revisions to Part 75. The final rule contains two main differences to the NO_X mass monitoring and reporting provisions from what was proposed. The first is that a new methodology for calculating NO_X mass emissions is included. This methodology utilizes a NO_X concentration CEM and a flow CEM to calculate NO_X mass emissions. The second is that sources that are not subject to title IV are not required to monitor and report data outside of the ozone season unless otherwise required to do so by the Administrator or the permitting authority administering the NO_X mass trading program.

The final rule also contains two main differences from the proposal with regard to the new excepted monitoring methodology for low mass emitters. The first is that the methodology is applicable to units with calculated NO_X mass emissions of up to 50 tons, rather than 25 tons as proposed. The second is that in lieu of using default rates for NO_X set forth in the rule, the owner or operator of a unit using this methodology may instead elect to determine a unit specific rate by conducting stack testing. All of these changes are discussed in greater detail in Appendix A of this notice. At this time EPA is only addressing the comments dealing with the two main issues for which EPA is finalizing revisions to part 75, the reporting of NO_X Mass (subpart H) and a new excepted monitoring methodology for low emitters (§ 75.19). The EPA intends to address the rest of the comments on the part 75 rulemaking in a separate, future rulemaking. The discussions in Appendix A also address comments received in the SNPR docket (A–96–56) that related specifically to the monitoring requirements set forth in part 75.

E. Emission Limitations/Allowance Allocations

Each State has the ultimate responsibility for determining the size of its trading program budget and its individual source allocations as long as the trading budget plus emissions from all other sources do not exceed the State's SIP Call budget. The proposed rule published on May 11, 1998 set timing requirements identifying when the allocations should be completed by each State and submitted to EPA for inclusion in the NO_X Allowance Tracking System (NATS) and provided an option specifying how a State might allocate NO_X allowances to the NO_X budget units. Today's final model rule clarifies the timing requirements for submission of allowance allocations to EPA and provides an optional allocation approach. Each State remains free to adopt the Model Rule's allocation approach or adopt an allocation scheme of its own provided it meets the specified timing requirements, requires new sources to hold allowances, and does not allocate more allowances than are available in the State trading budget.

1. Timing Requirements

In the SNPR, EPA set timing requirements identifying when a State would finalize NO_X allowance allocations for each control period in the NO_X Budget Trading Program and submit them to EPA for inclusion into the NATS. In developing the proposal, the Agency reasoned that uniform timing requirements would be important to ensure that all NO_X budget units in the trading program would have sufficient time and the same amount of time to plan for compliance for each control period, and sufficient time and the same amount of time to trade NO_X allowances. After considering a range of timing requirements, EPA proposed options that allocated NO_X allowances 5 to 10 years in advance of the applicable control period. The proposal attempted to strike a balance between systems that change the allocations on an annual basis and systems that establish a single, permanent allocation.

The proposed rule included the following timing requirements for the allocation of NO_X allowances: by September 30, 1999, each participating State would submit NO_X allowance allocations to EPA for the control periods in the years 2003, 2004, 2005, 2006, and 2007. After the initial allocation, two timing requirements were proposed for allocations following the year 2007. The option set forth in the proposed Model Rule would require a State to submit allocations to EPA for the control period in the year that is 5 years after the applicable submission deadline. For example, by January 1, 2003 each State participating in the trading program would issue its allocations for the control period in 2008. The State would issue allocations for the 2009 summer season by January 1, 2004. The second option, discussed in the preamble of the supplemental notice, would require the State to submit five years' worth of allowance allocations at a time, every five years, starting in 2003. For example, by January 1 , 2003, each State participating in the trading program would issue allocations for the control periods in the years 2008 through 2012. The supplemental notice solicited comment on these timing options as well as the full range of possible timing requirements (including a single, permanent allocation system and an annually changing allocation system). The supplemental notice also solicited comment on a provision requiring EPA to allocate NO_X allowances to NO_X budget units if a State were to fail to meet the timing requirements.

Comments: Although comments covered the entire range of possible timing requirements, commenters generally supported striving for administrative simplicity and ensuring sufficient planning horizons for affected sources, while still addressing the needs of a changing marketplace. Most comments fell into one of five categories.

First, a few commenters favored the option set forth in the proposed Model Rule that would update the allocations each year, five years in advance of the applicable control period. However, most of these commenters also supported a system which would update the allocations less than five years prior to the applicable control period as that would allow more recent data to be used in the allocations. One commenter advocated allocating for the previous season based on current year data (i.e., allocations would be issued at the end of the season for the preceding control period).

Approximately ten commenters favored the approach which would issue allowances five to ten years in advance. This group found that five to ten years of allocations satisfies the desire to have a sufficient planning horizon while still ensuring responsiveness to changing market conditions. Utilities generally opposed allocating single year allowances as it might be disruptive to utility planning.

The third category of commenters advocated longer term or permanent allocations. Most utility and business commenters favored allocations that were issued in ten year blocks at a minimum to provide sufficient time to plan future activities and amortize investments. A report submitted by a State proposed that allocations extend over the capital life of equipment, which was at least ten years.

A fourth set of commenters, which included three States, favored shorter term allocations. These States commented that they may want to base their allocations on more recent data than that proposed by the Model Rule and suggested that three years would provide sufficient planning time for sources. One State suggested tying allocations to the submission of triennial inventories.

A final group of commenters suggested that no timing requirement was necessary. They suggested that just as sources may participate in an interstate trading program with allocations based upon different methodologies, those same sources may participate in such a program even if they receive their allowances at different times or for different periods.

Several State commenters asserted that September 1999 was too early to have allocations set. These States suggested that the allocation process is difficult and takes longer than one year. One State suggested that the early allocation deadline would effectively prevent States from issuing allowances based upon output for the first period because an output approach could not be developed in time.

Response: Most commenters supported issuing allowances at least a couple of years prior to the season in which they would be used. The commenters generally cited the goal of balancing changing market conditions with providing sufficient planning horizons, as had the Agency in the proposal. The EPA agrees that the certainty in having allowances at least a couple of years into the future would provide some predictability for sources in their control planning and build confidence in the market. Most of the State commenters suggested three years prior to the control season as an adequate length of time for sources to know their allocations. The Agency agrees that a trading system could work with sources knowing their allocations three years prior to the control season. Therefore, EPA has modified its original proposal to ensure that sources would always have allowances at least three years in advance of the use date.

In addition to addressing how many years in advance the allocations are determined, the Agency has also considered whether allocations should be issued one control period at a time or for multiple control periods at a time (e.g., five to ten control periods). In response to the comments received, the Agency has determined that it would be appropriate to set minimum timing requirements rather than prescribing a set length of time for all States. Therefore, the Agency is now requiring States choosing to participate in the NO_X Budget Trading Program to allocate a minimum of one summer season of allowances at a time (at least three years in advance of the applicable control period).

Moving from requiring five summer seasons of allocations (three years in advance of the first season) to one summer season of allocations (three years in advance) has the advantage of allowing the allocation system to be updated sooner with more recent data. This would provide those States that want to use updating systems to more fully avail themselves of an updating system. The system could also incorporate new sources more quickly, thus reducing the need for larger new source set-asides.

However, the Agency has determined that a State may decide to issue allowances further into the future than the one-season minimum period required by this final rule and still receive streamlined EPA review of its trading program. The NO_X Allowance Tracking System will be able to handle allocations for longer periods. Therefore, this Final Rule sets out minimum timing requirements of one season (three years in advance), but States may issue allocations in larger blocks for as many as 30 seasons into the future and still receive streamlined EPA review. However, in determining the length of time for which a State issues allocations, a State should consider any potential adjustments that may occur to its future State budgets. For example, as stated in Section III.B.5.

of this preamble, the Agency may establish new budget levels for the post-2007 timeframe. States issuing long-term allocations should address how the allocations would be adjusted if new budget levels are established in the future. The Agency does believe that having allocations three years prior to the relevant control period would be the minimum needed to support an active multi-state trading market intended to reduce compliance costs for all States involved.

The three-year minimum timing requirement also is compatible with beginning the program in 2003, with at least the first year's allocations submitted to EPA by September 30, 1999. Sources will know their first year's allocations three years prior to the start of the program, and by April 1, 2003, all sources will have allocations for at least four seasons—2003, 2004, 2005 and 2006. The Agency maintains that the first year's allowances should be issued by September 30, 1999 to provide some predictability for sources in their control planning and build confidence in the market. It also ties in with the State's SIP submittal deadlines. For States participating in the trading program, the allowances are an integral part of the State's plan to satisfy the requirements of this SIP call. For sources in the Trading Program, the allowances are the mechanism by which State budget requirements are translated into source-specific limitations, and therefore the allocations should be submitted with the SIP submittals. In response to States who are worried about completing allocations in this time frame, EPA notes that one State in the OTC resolved its allocations in six weeks, demonstrating that it is possible to establish allocations in less than one year.

Requiring only one year's worth of allowances at a time has the added benefit of being able to more quickly accommodate States that want to switch allocation methodologies after the start of the program. For example, a State may decide to issue its initial allocations based on heat input data because it has not yet finalized an approach to issuing output-based allocations. The State could take a few additional years to refine the alternative approach to issuing allowances. When the State is ready to adopt the output approach, the State would be able to start using the new approach much sooner than it would be able to under a system that issued allocations in larger blocks.

Therefore, this preamble sets the following timing requirements for the allocation of NO_X allowances which will be able to accommodate States that want to issue allocations one year at a time as well as States that would like to issue allocations in larger blocks: by September 30, 1999, the State would submit NO_X allowance allocations to EPA for at least the control period of 2003. After this initial allocation, by April 1 of every year starting in 2001, the State must, at a minimum, submit allowance allocations to EPA for the control period in the year that is three years after the applicable submission deadline. For example, by April 1, 2001, a State would submit allocations for the control period in 2004. By April 1, 2002, a State would submit allocations for the control period in 2005. This minimum requirement would allow a State to submit blocks of allowances that represent any number of years should the State prefer to do so. For example, by the September 30, 1999 deadline, a State could submit allocations for only the 2003 control period or for multiple control periods (e.g., the five control periods of 2003–2007). The SIP would provide that if the State fails to submit allocations by the required date, EPA would allocate allowances based on the previous year's allocation within 60 days of the applicable deadline. This approach would ensure that starting in 2003, all sources would always have at least three years of allowances in their accounts.

Today's Model Rule presents an allocation approach that satisfies the minimum timing requirements. However, the initial allocation is for three control periods (2003–2005) because this would avoid updating allocations on an input basis. Any variation on the following approach would be acceptable providing it satisfies the minimum requirements specified in the previous paragraph. After this initial allocation, the model rule would have the State submit allowance allocations to EPA for the control period in the year that is three years after the applicable submission deadline. By April 1, 2003, a State would submit allocations for the control period in 2006. By April 1, 2004, a State would submit allocations for the control period in 2007, and so forth.

2. Options for NO_X Allowance Allocation Methodology

The Agency proposed that the NO_X Budget Trading Rule include a recommended NO_X allowance allocation methodology. The proposed Model Rule laid out an example of an allocation methodology using heat input data for source allocations. The preamble to the proposed Model Rule solicited comment on this methodology as well as two additional options using either input or output data for determining allocations. The first alternative to using heat input would base the allocation recommendation on heat input data for the first five control periods of the trading program and then convert the allocations to an output basis for the control periods after 2007. The final option would base the allocation recommendation on output data for all NO_X Budget units from the start of the trading program. The Agency also solicited comment on a suggested schedule for establishing a method for output-based allocations, and on any technical or data issues relevant to output-based allocations, as well as on the use of a fuel-neutral or output-neutral calculation to determine allocations for NO_X Budget units.

Comments: The Agency received numerous comments on the issue of whether to suggest an allocation recommendation to States. Approximately 25 commenters suggested that no recommendation is necessary. Many of these commenters emphasized that EPA had no authority to prescribe an allowance allocation methodology and a recommendation could be misinterpreted as a requirement for SIP approval. Several commenters requested that EPA clarify that the SIP approval process will be consistently applied to all States regardless of the allocation method chosen by a State, as long as the total allocation does not exceed a State's trading budget. Approximately half of the commenters who stated that no recommendation was necessary suggested that if EPA were going to make a recommendation, the recommendation should be a heat input approach.

Close to fifty commenters suggested that an Agency recommendation was a good idea, but they were divided on the appropriate methodology. This group included all the State commenters who suggested that a recommended approach was appropriate for use as a default allocation mechanism by States that did not determine their own allocations.

Many commenters supported the heat input approach used in the example in the supplemental notice. Two State commenters said that the proposed example approach was a useful default for States that did not come up with their own allocations. Other commenters suggested that heat input is an easily understood metric for all sources and the data is readily available.

However, many suggested that EPA should recommend an output method because they believe output-based allocations tend to reward more efficient fuels over fuels that require a higher heat input to generate the same amount of electricity. Other reasons cited for output-based allocations include the incentive that updating output allocations provides for reducing emissions of pollutants such as CO_2 and mercury. Several commenters suggested that output-based allocations would allow the environmental goals of the program to be achieved more cost-effectively; their arguments rested upon assertions that issuing allowances to non-NO_X emitting units in an output-based system would reduce the need for NO_X controls over time. One State commenter said that an output approach was the consensus of participants at EPA Workshops held prior to drafting of the Supplemental Notice and therefore should be the recommended approach suggested by EPA.

One commenter had a specific recommendation for an updating output-based allocation system which would issue allowances each year for the current control period. Administrative simplicity, economic efficiency, incentives for innovation, and lower consumer impact were cited as reasons supporting that position.

Additional commenters favored the output-based approach but only for fossil-fuel fired sources and renewables. Several commenters submitted letters opposing a ''fuel-neutral'' policy and objected to including nuclear sources in an output allocation to sources. They stated that a fuel neutral policy would provide incentives for nuclear generation which has the potential to release small amounts of radiation to the environment as well as the potential for generation of high-and low-level radioactive waste.

Response: As was stated in the SNPR, EPA believes that it is important for as many States as possible to participate in the NO_X Budget Trading Program. The Agency recognizes that States have unanimously favored flexibility in developing their own allocation methodologies. Further, the comments that EPA received in response to the SNPR (as well as in response to the workshops held prior to publication of the SNPR) provided no clear consensus for one methodology over another.

However, the Agency believes it is important to provide a model allocation methodology that States may choose to use as a guide for their own allocation process. Several States have commented that including an example method in the Model Rule would be useful as a backup for States who do not come up with an alternative method of allocation. An outlined approach in the Model Rule may also facilitate the regulatory process within a State that wants to quickly adopt the Model Rule.

Therefore, today's Model Rule includes an optional allocation methodology. The Agency has carefully considered arguments for alternative allocation methods. The EPA would support a decision by a State to use either heat input or output data as a basis for source allocations or for the State to auction some or all of its allocation. In determining the basis for the methodology presented in today's Model Rule, EPA has decided to use the heat input approach because it is concerned that an output-based approach has not been fully developed or made available for public comment. Further, before issuing a model output-based allocation approach, the Agency would need to make several revisions to current reporting and monitoring provisions. EPA would have to revise part 75 to monitor and report temperature, pressure, and steam heat output (mmBtu) for units with some or all of their output as heated steam. EPA would also need to put in place procedures which take advantage of the most accurate data possible. For example, the Energy Information Administration (EIA) solicited comment in a July 17, 1998 **Federal Register** Notice on a proposal to make electricity generating data non-confidential and publicly available from non-utility electricity generators (63 FR 38620). EPA will not know if this information is available to the Agency or to States through EIA for some time. If EIA were to decide that this information should remain confidential in the future, then EPA and States would need to collect their own data from sources. Additionally, the Agency is currently unaware of any public databases of output information besides those for electrical generation output for certain electrical generating units. Output information would only become available if sources report it directly to the Agency or to States.

While today's final Model Rule includes a heat input approach, the Agency is continuing to work on developing an updating output approach to source allocations. For States that wish to use output in developing their source allocations and are willing to wait for EPA to finalize such an approach, EPA plans to issue a proposed system for output-based allocations in 1999 and finalize an output-based option in 2000. However, the Agency's ability to issue an output-based approach on this schedule is contingent upon resolving the issues and promulgating the necessary rule changes mentioned in the previous paragraph.

Assuming EPA finalizes an output-based option in early 2000, States wishing to use this output-based system could adopt the necessary rules, and output data could be measured and collected at NO_X budget units during the control periods in the years 2001 and 2002. Output data could then be available for States to calculate allocations for the control periods starting in 2006. Heat-input-based allocations could be used for the 2003 through 2005 control seasons.

However, this does not prohibit a State from developing its own output-based system on a faster timeline. For example, if a State has developed an output-based approach for use in its initial allocations, it may use that approach. Or, the State may issue its initial allocation for 2003 using heat input data and then by April 1, 2001 issue output allocations for the control periods starting in 2004.

The Agency recognizes that a State's choice of when and for what blocks of time it issues allocations is intertwined with the choice of allocation methodology. Several commenters suggested that more incentives for generation efficiency and therefore ancillary environmental benefits (CO_2 and mercury reductions) are provided in an output system with periodic updates, and those incentives are lost in an heat input system that is periodically updated. These commenters suggested that with a heat-input-based system, States should issue permanent allocations rather than updating the allocations. An allocation system that issues permanent streams of allowances (using either a heat input or an output methodology) would still provide an incentive for generation efficiency although perhaps not to the extent that an updating output system might. However, if a State issues a permanent stream of allowances to existing sources, that State would have to decide how to address new sources (options include establishing an allocation set aside or an auction, or requiring new sources to obtain allowances from existing sources).

3. New Source Set-Aside

The Agency proposed an allocation set-aside account equaling 2 percent of the State trading program budget for each control period for new NO_x Budget units as part of its recommended allocation approach. The concept and size of the set-aside is included only as an optional feature of the Model Rule; however, the Model Rule requires new sources to hold allowances to cover their emissions. The supplemental notice proposed that allowances from the set-aside be given out on a first-come, first-served basis at an emission rate of 0.15 lb/mmBtu multiplied by a budget unit's maximum design heat input. The source would then be subject to a reduced utilization calculation so that a reduction in the emission rate below 0.15 lb/mmBtu would be rewarded, but a reduction in utilization would not. In other words, EPA would deduct NO_x allowances following each control period based on the unit's actual utilization for the control period. After the deduction, the allocation that had been granted to the new unit from the set-aside would equal the product of 0.15 lb/mmBtu and the budget unit's actual heat input for the season. EPA solicited comments on the use of a set-aside as part of the recommended allocation methodology as well as the proposed size and operation of the set-aside.

Comments: The Agency received many comments regarding the proposal for a new source set-aside. While several commenters were opposed to a new source set-aside because it might bias control decisions in favor of adding new sources relative to controlling existing sources, numerous other commenters expressed general support for accommodating new sources with allowances.

Several of these commenters offered suggestions for how the set-aside should be designed. A few commenters stated that the size of the set-aside should be related to the timing requirements and noted that shorter timing requirements make it easier to accommodate new growth. One commenter who advocated annually updating the allocation system noted that its proposal would eliminate the need for a new source set-aside. Some commenters supported the set-aside concept but asserted that States should be able to decide the correct size. Other commenters agreed with the set-aside concept in theory but did not think the allowances should come from existing sources.

Additional commenters had specific proposals for the size of the set-aside. One commenter suggested that the size of the set-aside should reflect the actual growth projected in budget calculations and that the unused portion of the set-aside should be retired. A few commenters agreed with the proposed 2 percent size.

Several commenters offered suggestions on how to issue the set-aside allowances to new sources. One commenter suggested that the allowances should be given to new sources at the actual emission rate if it was below the proposed 0.15 lb/mmBtu level.

Finally, several commenters suggested that the concept of a set-aside was an issue that should be left completely up to the States.

Response: The Agency believes that a new source set-aside should be large enough to provide all new units entering the trading program with allocations. The Agency maintains that as much as possible within the context of the overall trading budget, allocations should be provided to new sources on the same basis as that used for existing units until the time when the new sources receive an allocation as part of an updating allocation system. Therefore, the Agency continues to include a new source set-aside as part of its optional allocation methodology described in the Model Rule. The EPA proposed the 2 percent set-aside in the SNPR after looking at the amount of growth from new sources projected by the Integrated Planning Model (and used in the budget determinations) and estimating how much growth could be expected over the five year period that new sources might have to wait before receiving an allocation. In light of the allocation methodology and timing specified in today's Model Rule as well as revisions made to the growth factors used in State budget determinations since the SNPR, the Agency has re-evaluated the size of the new source set-aside proposal. The revised Integrated Planning Model projects approximately ½ percent annual growth in capacity utilization for new sources. Given the timing and optional allocation methodology specified in today's Model Rule, the 2003, 2004, and 2005 set-aside would need to accommodate any source that started operating after May 1, 1995. Assuming the ½ percent growth rate projected by IPM, the Agency finds that a 5 percent set-aside should be large enough to accommodate all new sources for the 2003, 2004, and 2005 control seasons.

After 2005, the new source set-aside would need to accommodate any source that commenced operation after May 1 of the control period three years prior to the control period in which the set-aside would be available. For example, in 2006, the set-aside should be large enough to accommodate any source that commenced operation after May 1, 2003. Assuming the growth rates predicted by the IPM, the Agency finds that a 2 percent set-aside should be large enough to accommodate new source growth after May 1, 2003.

A 5 percent set-aside provision for the first three control seasons and 2 percent for the control periods starting in 2006 is incorporated into today's Model Rule as an option States may adopt. However, States may choose to handle new sources in any way as long as the emissions from new sources are subject to the overall State budget. For example, some States may choose to issue allowances for longer periods of time than that outlined as the minimum requirement in today's Model Rule. These States may find that a 5 percent set-aside is not sufficient to accommodate all their new source growth, and may want to consider a larger set-aside or alternative means to accommodate new sources. Or, States may decide to allocate allowances based on a new source's permitted or actual emissions, which may be lower than 0.15 lb/mmBtu. This would require a smaller set-aside.

In the model rule set-aside provision, allowances will be issued to new sources on a first-come, first-served basis. Allowances that are not issued to new sources in the applicable control period will be returned to the existing sources in the State on a pro-rata basis to guard against the possibility of a disproportionately large set-aside.

The EPA maintains its position that new sources should receive allowances at the same rate as that applied to existing sources (i.e., large electric generating units would receive allowances at a 0.15 lb/mmBtu rate, large non-electric generating units would receive allowances at the average emission rate for existing large non-electric generating units after controls are in place, as explained in section 4 below). However, to reinforce the flexibility available on these issues, as long as a State requires new sources to hold allowances, the Agency reiterates that States may have any size set-aside (including zero), may allocate the set-aside in whatever manner they choose, and may carry over from one year to the next any amount of allowances (subject to the banking provisions on this SIP call). If a State decides to return unused allowances from a new source set-aside to existing sources, the State would indicate to EPA (as the administrator of the allowance tracking system) what number of allowances should be returned to which existing units.

4. Optional NO_X Allocation Methodology in Model Rule

While specific source allocations are required for States participating in the NO_X Budget Trading Program, the allocation methodology presented here is an optional approach that may be adopted by States. As long as a State (1) does not allocate more allowances than are available in the State NO_X trading budget, (2) requires new sources to hold allowances, and (3) issues allocations on a schedule that meets the minimum timing requirements, the State may adopt whatever methodology it finds the most appropriate and still qualify for inclusion in the NO_X Budget Trading Program.

The Model Rule contains the following optional allocation methodology. It differs from the approach presented in the proposed rule on the timing provisions, the allocation methodology for non-electric generating units, and the size of the optional new source set-aside. As proposed in the SNPR, initial unadjusted allocations to existing NO_X Budget units serving electric generators would be based on actual heat input data (in mmBtu) for the units multiplied by an emission rate of 0.15 lb/mmBtu. For the control periods in 2003, 2004, and 2005, the heat input used in the allocation calculation for large electric generating units equals the average of the heat input for the two highest control periods for the years 1995, 1996, and 1997. Once the State completes the initial allocation calculation for all the existing NO_X budget units serving electric generators for 2003, 2004, and 2005, the State would adjust the allocation for each unit upward or downward so that the total allocations match the aggregate emission levels apportioned by an approved SIP to the State's NO_X Budget units serving electric generators. Then, the State would adjust the allocation for each unit proportionately so that the total allocation equals 95 percent of the aggregate emission levels apportioned to the State's NO_X Budget units serving electric generators (to provide for the 5 percent new source set-aside). A State would submit the 2003, 2004, and 2005 allocations to EPA by September 30, 1999.

For the control periods starting in 2006, the heat input used in the allocation calculation for large electric generating units equals the heat input measured during the control period of the year that is four years before the year for which the allocations are being calculated. Once the State completes the initial allocation calculation for all existing budget units, and the State adjusts the allocations to match the aggregate emission levels apportioned to NO_X Budget units serving electric generators, the State would adjust the allocation for each unit proportionately so that the total allocation equals 98 percent of the aggregate emission levels apportioned to NO_X Budget units serving electric generators (to provide for the 2 percent new source set-aside).

For reasons explained elsewhere in today's rulemaking, EPA determined the aggregate emission levels for large non-electric generating units in each State budget based upon a 60 percent reduction rather than the 70 percent proposed in the SNPR. The 60 percent reduction results in an average emission rate across the region of 0.17 lbs/mmBtu for large non-electric generating units. Therefore, initial unadjusted allocations to existing large non-electric generating units would be based on actual heat input data (in mmBtu) for the units multiplied by an emission rate of 0.17 lb/mmBtu. For non-electric generating units subject to the trading program, 1995 heat input data is used in the allocation calculation for the control periods 2003, 2004, and 2005 (1995 is the most recent data the Agency knows is currently available for non-electric generating units). Once the State completes the initial allocation calculation for all the existing large non-electric generating units for 2003, 2004, and 2005, the State would adjust the allocation for each unit upward or downward so that the total allocations match the aggregate emission levels apportioned by an approved SIP to the State's large non-electric generating units. Then, the State would adjust the allocation for each unit proportionately so that the total allocation equals 95 percent of the aggregate emission levels apportioned to the State's large non-electric generating units (to provide for the 5% new source set-aside). A State would submit the 2003, 2004, and 2005 allocations to EPA by September 30, 1999.

For the control periods starting in 2006, the heat input used in the allocation calculation equals the heat input measured during the control period of the year that is four years before the year for which the allocations are being calculated. Once the State completes the initial allocation calculation for all existing budget units, and the State adjusts the allocations to match the aggregate emission levels apportioned to large non-electric generating units, the State would adjust the allocation for each unit proportionately so that the total allocation equals 98 percent of the aggregate emission levels apportioned to large non-electric generating units (to provide for the 2% new source set-aside).

A State would establish a separate allocation set-aside for new units each control period. Five percent of the seasonal trading budget will be held in a set-aside account for the control periods in 2003, 2004, and 2005. At the end of the relevant control period, the State would submit a NO_X allowance transfer request to EPA to return any allowances remaining in the account to the existing sources in the State on a pro-rata basis.

The allowances would be issued to new sources on a first-come first-served basis at a rate of 0.15 lb/mmBtu for NO_X Budget units serving electric generators and 0.17 lb/mmBtu for large non-electric generating units multiplied by the budget unit's maximum design heat input. Following each control period, the source would be subject to a reduced utilization calculation, in which EPA would deduct NO_X allowances based on the unit's actual utilization. Because the allocation for a new unit from the set-aside is based on maximum design heat input, this procedure adjusts the allocation by actual heat input for the control period of the allocation. This adjustment is a surrogate for the use of actual utilization in a prior baseline period which is the approach used for allocating NO_X allowances to existing units.

F. Banking Provisions

As explained in Section III.F.7., EPA requested comment in the SNPR on whether and how banking should be incorporated into the design of the NO_X Budget Trading Program. Banking may generally be defined as allowing sources that make emissions reductions beyond current requirements to save and use these excess reductions to exceed requirements in a later time period. Options ranged from a program without banking to several variations of a program with banking, prior to and/or following the start of the program. The EPA also requested comment on options for managing the use of banked allowances in order to limit the emissions variability associated with banking. The EPA specifically proposed using a ''flow control'' mechanism in cases where the potential exists for a large amount of banked allowances to be available.

This section addresses how banking has been incorporated into the NO_X Budget Trading Program based on the criteria set forth in the NO_X SIP call.

1. Banking Starting in 2003

In accordance with the provisions discussed in III.F.7.a., trading programs used to comply with the NO_X SIP call may allow banking to start in the first control period of the program, the 2003 ozone season. The majority of commenters supported banking in the context of the NO_X Budget Trading Program. Based on the advantages that banking can provide, as discussed in the SNPR and the comments, the NO_X

Budget Trading Program has been designed to allow banking starting in the first control period of the trading program. NO_X Budget units that hold additional NO_X allowances beyond what is required to demonstrate compliance for a given control period may carry-over those allowances to the next control period. These banked allowances may be used or sold for compliance in future control periods.

2. Management of Banked Allowances

The NO_X SIP call establishes that a flow control mechanism be paired with any banking provisions to limit the potential for emissions to be significantly higher than budgeted levels because of banking. This mechanism allows unlimited banking of allowances saved through emissions reductions by sources, but discourages the ''excessive use'' of banked allowances by establishing either an absolute limit on the number of banked allowances that can be used each season or a rate discounting the use of banked allowances over a given level. In the SNPR, EPA solicited comment on the application of flow control in the NO_X Budget Trading Program. Although many commenters were opposed to any restrictions on the use of banked allowances, several commenters stated that if restrictions were to be imposed, they would favor flow control as the most cost-effective, least rigid means of management. A few commenters added that, if implemented, flow control should be applied on a source-by-source basis so as to avoid penalizing all of the participants in the trading program for the excess banking of individual participants. One commenter stated that if EPA concludes that there is an adequate basis for imposing some type of restriction, it should avoid placing any absolute limit on the amount of banked allowances that can be used in a given season.

The NO_X SIP call established that flow control should be set at the 10 percent level. The effect of setting flow control at 10 percent of the trading program budget is that on a season-by-season basis, sources may use banked allowances or credits for compliance without restrictions in an amount up to 10 percent of the NO_X budget for those sources in the trading program. Banked allowances or credits that are used in an amount greater than 10 percent of the NO_X budget for those sources will have restrictions on their use.

The following provides a brief description of exactly how the flow control mechanism will operate in the NO_X Budget Trading Program. The number of banked allowances held by all participants in the multi-state trading program will be tabulated each year following the compliance certification process to determine what percentage banked allowances are of the overall multi-state trading budget for the next year. If this percentage is equal to or below 10 percent, all banked allowances may be used in the upcoming control season on a one allowance for one ton basis. If this percentage is greater than 10 percent, flow control will be triggered. In years when flow control is triggered, a withdrawal ratio will be established prior to the control period for which it would apply. The withdrawal ratio will be calculated by dividing 10 percent of the total trading program budget by the total number of banked allowances. This ratio will be applied to each compliance or overdraft account (only accounts used for compliance) holding banked allowances as of the allowance transfer deadline at the end of the control period for which it applies. Banked allowances in each account may be used for compliance on a one-for-one basis in an amount not exceeding the amount established by the withdrawal ratio. Banked allowances used in an amount exceeding that established by the withdrawal ratio must be used on a two-for-one basis. By setting the withdrawal ratio prior to the applicable control period (in years flow control is triggered) and applying it at the time of compliance certification at the end of the applicable control period, sources have one full control period to incorporate the value of using banked allowances into their operations.

As described above, the NO_X Budget Trading Program applies the flow control mechanism on a regional basis and establishes a 2-for-1 discount for banked allowances that are used in an amount greater than the flow control limit. The regional approach for applying flow control was selected over the source-by-source approach for the following reasons:

- EPA believes this option provides more flexibility to individual sources than the source-by-source approach. If the 10 percent limit were placed on each source based on the source's allocation, the limit would be in effect every year for every source, even when the amount of banked allowances throughout the entire trading region was below 10 percent of the regional trading budget. In contrast, the regional approach only applies flow control when the amount of banked allowances throughout the region (entire multi-state trading area) exceeds the 10 percent limit. In response to the commenter suggesting that the regional approach penalizes all participants in the trading program for the excess banking of individual participants, EPA notes that it would be difficult for a few sources to cause the entire regional bank to exceed 10 percent of the budget. In addition, based on the analyses presented in the RIA, EPA does not anticipate that flow control is likely to be triggered. Consequently, flow control is more of an insurance policy, rather than a provision that is routinely expected to be operational.
- The regional approach also provides flexibility to sources if and when it is triggered. Because the withdrawal ratio is set before the applicable control period but not applied until the control period's allowance transfer deadline, sources have over seven months to manage the amount of banked allowances they use on a 1-for-1 basis versus a 2-for-1 basis.
- EPA believes the regional approach is also a more universal approach than the source-by-source approach under a variety of allocation programs that States may use in the NO_X Budget Trading Program. To apply the flow control mechanism on a source-by-source basis, the 10 percent limit would be applied to each source's allocation. In this way, a source could use an amount of banked allowances up to 10 percent of it's allocation without restrictions. Restrictions would be placed on banked allowances that the source uses in an amount greater than 10 percent of its allocation. Under certain allocation programs, States may choose not to allocate NO_X allowances to new sources and require that these sources obtain the necessary amount of NO_X allowances for compliance from the market. By not having an allocation of NO_X allowances, new sources would be prevented from using banked allowances under the source-by-source approach. EPA believes that approaches to accommodate sources without a fixed allocation under the source-by-source flow control approach would overly complicate the system.
- The regional approach for applying flow control is also the approach used in the Ozone Transport Commission's (OTC) trading program. Because the NO_X Budget Trading Program is designed to include States currently operating in the OTC program, using the same approach for flow control will minimize the disruption for these sources to convert to the NO_X Budget Trading Program.

The other issue for flow control is the type of restriction to place on banked allowances used in an amount greater than the 10 percent limit. The NO_X Budget Trading Program includes the 2-for-1 discount as the applicable restriction. EPA agrees with the commenters that favored this approach over using an absolute limit. The EPA believes the 2-for-1 discount provides more flexibility for sources to achieve compliance than is offered by the absolute limit. The discount is also beneficial to the environment, when triggered, by allowing only one ton of NO_X emissions for every two tons removed. Additionally, the OTC program uses the 2-for-1 discount.

The following example illustrates how flow control will be used. For the year 2006, assume the total trading program budget across all States equals 300,000 allowances and 35,000 allowances are banked from control periods prior to the 2006 control period. Since more than 10 percent (35,000/300,000 = 11.7%) of the total trading program budget is banked, a withdrawal ratio will be established prior to the 2006 control period and will apply to all compliance and overdraft accounts (only accounts that may be used for compliance) holding banked allowances at the end of the 2006 control period. In this case, the withdrawal ratio would be 0.86 (determined by dividing 10 percent of the total trading program budget by the total number of banked allowances, or 30,000/35,000). Thus if a source holds 1,000 banked allowances at the end of the 2006 control period, it will be able to use 860 on a 1-for-1 basis, but will have to use the remaining 140, if necessary, on a 2-for-1 basis. As a result, if the source used all its banked allowances for compliance in the 2006 control period, the 1,000 banked allowances could be used to cover only 930 tons of NO_X emissions (860 + 140/2). Of course, a source could buy additional current year allowances to cover emissions on a 1-for-1 basis or buy additional banked allowances (allowances not needed by other sources for compliance) to increase the amount of banked allowances it may use on a 1-for-1 basis.

3. Early Reduction Credits

As described in section III.F.7.c., the majority of commenters generally supported the option of awarding early reduction credits. EPA is allowing, but not requiring, States to grant early reduction credits to sources for reductions in ozone season NO_X emissions prior to the 2003 ozone season. States may issue early reduction credits in an amount not exceeding the State's compliance supplement pool. The compliance supplement pool is further explained in section III.F.6.

Based on the support the commenters on the NO_X Budget Trading Program expressed for early reduction credits, EPA is including optional provisions in the trading program that States may use for issuing credits. States participating in the NO_X Budget Trading Program that choose to issue early reduction credits may follow the methodology included in part 96 or may develop their own methodology, provided the State's program meets the following requirements. The State program must ensure that early reduction credits will not be issued in an amount exceeding the State's compliance supplement pool. The State program must also meet the criteria for early reduction credits discussed in section III.F.7.c. Finally, the State should notify EPA of the amount of credits issued to particular NO_X Budget units by no later than May 1, 2003. Early reduction credits shall be issued to units as allowances for the 2003 control period. For purposes of the banking provisions, the allowances will not be considered banked in the 2003 control period. However, any unused allowances carried from the 2003 control period to the 2004 control period shall be considered banked as will be the case for all unused allowances carried over to the next control period. Per the requirements discussed in section III.F.7.c., allowances issued for early reduction credits may be used for compliance by sources in the 2003 and 2004 control periods. Any of these allowances that are not used for compliance in the 2003 or 2004 control periods shall be retired by EPA from the account in which they are held.

As discussed in Section III.F.6.b.ii., States also have the option of issuing some or all of the State's compliance supplement pool directly to sources according to the criteria for direct distribution. Consequently, States participating in the NO_X Budget Trading Program may also use the direct distribution option for issuing the compliance supplement pool. In this case, the State must notify EPA by May 1, 2003 of the specific NO_X Budget units that will be receiving the direct distribution.

4. Optional Methodology for Issuing Early Reduction Credits

The methodology described below is an optional methodology included in part 96 that States participating in the NO_X budget Trading Program and choosing to issue early reduction credits may follow. States participating in the NO_X Budget Trading Program may also choose to develop their own methodology as discussed above. The following methodology is designed to meet the criteria for issuing early reduction credits discussed in section III.F.7.c. and to provide incentives for a State's NO_X budget units to generate early credits in an amount no greater than the size of the State's compliance supplement pool. The State may choose to issue the entire compliance supplement pool as early reduction credits through this methodology, or the State may choose to reserve some of the compliance supplement pool to be issued to sources according to the direct distribution criteria as described above.

This methodology is applicable for reductions made during the 2001 and 2002 ozone seasons. NO_X budget units that request early reduction credits will be required to monitor ozone season NO_X emissions according to the monitoring provisions of part 75, subpart H by the 2000 ozone season. The information from the 2000 ozone season shall be used to establish a baseline emission rate for the NO_X budget unit. To be eligible for early reduction credits, a NO_X budget unit shall reduce its emissions rate in the 2001 and/or 2002 control period(s) no less than 20 percent below its baseline emissions rate established for the 2000 ozone season. The size of the early reduction credit request shall equal the difference between 0.25 lb/mmBtu and the unit's actual emissions rate multiplied by the unit's actual heat input for the applicable control period. NO_X Budget units requesting early reduction credits should submit the request to the State by no later than October 30 of the year for which the early reductions were generated.

The methodology conforms with the NO_X SIP call's criteria for early reduction credits. By requiring that the reductions be measured using provisions in part 75, the reductions will be verified as having actually occurred and will be quantified according to the same procedures as required for compliance with the general requirements of the NO_X Budget Trading Program. The procedure for calculating the credit request is intended to ensure that the reductions are surplus. Phase II of the title IV NO_X emissions limits are required to be installed at specific coal-fired boilers by January 1, 2000. By requiring that an early reduction credit must be generated by no less than a 20 percent reduction below the 2000 baseline emission rate, credits will only be issued for reductions that go below emissions levels achieved for compliance with title IV requirements. This provision ensures that the early reduction credits are only issued for reductions below existing requirements (i.e., surplus).

Calculating the early credit based on the difference between 0.25 lb/mmBtu and the unit's actual emissions rate establishes a standard emissions rate from which all early reduction credits are calculated. This approach ensures that sources with higher NO_X emissions rates prior to the 2001 ozone season are not provided an opportunity to generate more early reduction credits than relatively cleaner sources. In this way, all sources have an equal opportunity to generate early reduction credits below a standard emissions rate.

According to the requirements in the NO_X SIP call, States may not issue early reduction credits in an amount greater than the State's compliance supplement pool. To ensure this provision is met, the optional methodology is designed for States to issue all early reduction credits following the 2002 ozone season. By October 30, 2002, a State will have received all early reduction requests for both the 2001 and 2002 ozone seasons. After review of the requests, the State would issue credit to all valid requests according to the following procedure. If the amount of valid requests is less than the size of the State's compliance supplement pool, the State would issue one allowance for each ton of early reduction credit requested. If the amount of valid requests is more than the size of the State's pool, the State would reduce the amount in the credit requests on a pro-rata basis so that the requests equal the size of the State's pool. After the requests have been reduced, the State would then issue allowances based on the remaining size of each credit request. States would complete the issuance of allowances for the early reduction credit requests as soon as possible following October 30, 2002, but no later than May 1, 2003.

5. Integrating the OTC Program With the NO_X Budget Trading Program's Banking Provisions

The OTC NO_X Budget Program is a multi-state, capped NO_X trading program that begins in 1999 and includes many States subject to today's action. By the start of the NO_X Budget Trading Program under the NO_X SIP call, sources in the OTC program will potentially hold banked NO_X allowances resulting from early reductions and/or overcontrol with program requirements. At issue is the ability of OTC sources to use these banked allowances in the NO_X Budget Trading Program.

Commenters have supported allowing OTC sources to use banked allowances (i.e., early reductions from the 1997 and 1998 ozone seasons and unused allowances from the 1999 through 2002 ozone seasons) from the OTC program for compliance in the NO_X Budget Trading Program. Commenters have stated that because OTC sources will be subject to a market-based cap-and-trade program prior to the 2003 ozone season, it is important to create a smooth transition from the OTC program to the NO_X Budget Trading Program. They have suggested discounting OTC Phase II allowances to make them equivalent to those achieved under the NO_X SIP call. One OTC State suggested accomplishing this by adjusting the OTC banked allowances by a ratio of the Phase II OTC control requirement to the Phase III OTC control requirement, working with EPA to determine the exact ratio. A few OTC States suggested that OTC allowances banked in Phase II could be used as early reduction credits in the NO_X Budget Trading Program. A commenter from outside the OTC voiced concern that the use of OTC allowances banked by sources for the years 1999 through 2002 could distort the larger trading market established under the SIP call.

The EPA believes that the compliance supplement pool provides the opportunity to integrate the OTC program into the NO_X Budget Trading Program by allowing OTC States to bring their banked allowances into the NO_X Budget Trading Program as early reduction credits after the 2002 ozone season. The EPA established two primary criteria for the generation of early reduction credits in III.F.7.c.: first, the credits must be surplus, verifiable, and quantifiable; and second, a State may not grant an amount of early reduction credits in excess of a State's compliance supplement pool. EPA believes that banked allowances held by sources in the OTC program would qualify as being surplus, verifiable, and quantifiable. The banked allowances would be surplus because they would represent emissions reductions that go beyond what is required by the emissions limitations established by the OTC program in the applicable ozone seasons. The banked allowances would also be verified and quantified according to the procedures in the OTC program which are essentially identical to the requirements that will be in place under the NO_X Budget Trading Program.

As for the second criterion that a State issue no more early reduction credits than provided through the compliance supplement pool, EPA believes this could be addressed according to the following procedure. If the number of banked allowances held by an OTC State's NO_X Budget units, after the compliance certification process for the 2002 ozone season, is less than the number of credits available in the pool for that State, the NO_X budget units in that State may carry all of their banked allowances from the OTC program into the NO_X Budget Trading Program. The banked allowances brought in from the OTC program would be subtracted from the State's compliance supplement pool. Any remaining credits in the compliance supplement pool could be distributed by the OTC State through the direct distribution option, if necessary. If, on the other hand, an OTC State's NO_X Budget units hold banked allowances from the OTC program in excess of the amount of credits in the State's pool, after the compliance certification process for the 2002 ozone season, the State would need to reduce the amount of allowances eligible for being carried into the NO_X Budget Trading Program. This could be achieved by reducing the amount of banked allowances held by the units on a pro rata basis so that the number of allowances carried into the NO_X Budget Trading Program is less than or equal to the size of the State's compliance supplement pool.

The process described above provides a mechanism for OTC States to use the compliance supplement pool to carry banked allowances from the OTC program as of the end of the compliance period in 2002 over into the NO_X Budget Trading Program. The EPA believes this integration acknowledges the important reductions made in the OTC program prior to 2003 while providing similar opportunities for sources outside the OTC to generate credits for early reductions. Since all States in the NO_X Budget Trading Program will have an opportunity to receive credit for early reductions, EPA does not believe any market distortion will occur.

G. New Source Review

Under the New Source Review (NSR) provisions of section 173 of the CAA, a new major source or a major modification to an existing major source of a particular pollutant that proposes to locate in an area designated nonattainment for that pollutant must offset its new emissions. In the SNPR, the EPA solicited comment on whether and how the offset requirement could be met by sources' participation in the NO_X Budget Trading Program. The Agency stated its belief that sources obligated to obtain NO_X offsets under the NSR program should be able to do so by acquiring NO_X allowances through the trading program. In essence, the EPA reasoned that, where a trading program is a capped system, a new source's acquisition of allowances to cover its increased emissions would necessarily result in actual emissions reductions elsewhere in the system.

The EPA continues to believe that nonattainment NSR offset requirements of the CAA can be met using the mechanism of the NO_X Budget Trading Program. However, there are a number of complex issues involved with integrating these programs, for example, the statutory requirements to obtain offsets from certain geographic areas and, depending on the classification of the 1-hour ozone nonattainment area, at certain offset ratios. Because the Agency is continuing to evaluate these issues, it will not be providing guidance at this time on integrating these programs; however, the EPA intends to provide such guidance as soon as possible. At that time, the EPA will respond to the comments received on this topic in the course of this rulemaking.

VIII. Interaction With Title IV NO_X Rule

The EPA proposed, in the May 11, 1998 supplemental notice, to add a new § 76.16 to part 76, the Acid Rain NO_X Emission Reduction Program regulations. The purpose of the proposed § 76.16 was to increase utilities' flexibility in situations where units owned or operated by a utility were subject to both a NO_X cap-and-trade program and the Phase II NO_X emission limitations under the Acid Rain NO_X Emission Reduction Program. Under proposed § 76.16, a State or group of States could request that the Administrator relieve all units located in the State or States and otherwise subject to the Phase II NO_X emission limitations (under §§ 76.6 and 76.7) of the requirement to comply with such emission limitations. The Administrator could also take this action on his or her own motion. All Group 1 boilers (i.e., tangentially fired or dry bottom wall fired boilers) would remain subject to the Phase I NO_X emission limitations (under § 76.5), while Group 2 boilers (i.e., cell burner boilers, cyclones, wet bottom boilers, and vertically fired boilers) would have no NO_X limits under the Acid Rain Program. This relief would be available if all such units were subject, under a SIP or a FIP, to a NO_X cap-and-trade program meeting certain requirements. The NO_X cap-and-trade program had to include, *inter alia,* either an annual cap or seasonal caps that together limited total annual emissions and a requirement that each unit use authorizations to emit (or allowances) to account for all NO_X emissions. In addition, there had to be a demonstration that total annual NO_X emissions from all units otherwise subject to the Acid Rain NO_X emission limitations and located in the State or group of States would, under the NO_X cap-and-trade program, be equal to or lower than the total number of annual NO_X emissions if the units remained subject to the Acid Rain NO_X emission limitations. Alternative emission limitations and NO_X averaging plans under part 76 would not be taken into account in such a demonstration.

Although the purpose of proposed § 76.16 was to provide more flexibility to utilities consistent with the requirements of section 407, almost all utility commenters and many State and State agency commenters opposed the proposal. Many commenters argued that relieving a utility's units in one State of the applicability of the Phase II NO_X emission limitation would prevent the utility from using those units, along with units that the utility owns or operates in other States, in an interstate averaging plan under the Acid Rain Nitrogen Oxides Emission Reduction Program. Under section 407(e) of the CAA, as implemented under § 76.11, a utility may comply with the Acid Rain NO_X emission limitations by averaging the emissions of units that the utility owns or operates in the same State or other States. Many utilities have complied, or plan to comply, with the Acid Rain NO_X Emission Reduction Program by using averaging plans, including some interstate averaging plans. However, a unit that has no Acid Rain emission limitation obviously cannot be included in an averaging plan since EPA would have no authority under title IV to limit the unit's emissions, whether on an individual-unit or a group-average basis. Further, as a practical matter, the group average limit for any given year, which must be calculated based on the limit applicable to each individual unit in the averaging plan, could not reflect any limit for such a unit. *See* 40 CFR 76.11(a) (1) and (2) (allowing only units with Acid Rain NO_X emission limitations in effect to participate in an averaging plan) and (d)(1)(ii)(A) (showing calculation of the group average limit using each unit's Acid Rain NO_X emission limitation).

In the proposal, EPA attempted to address the issue of the potential impact of proposed § 76.16 on averaging plans. Proposed § 76.16(b)(1)(ii) required that, in determining whether a NO_X cap-and-trade program met the requirements for granting units relief from the Phase II NO_X emission limitations, the Administrator must consider ''whether the cost savings from trading will be offset by elimination of the ability of an owner or operator of a unit in the State or the group of States to use a NO_X averaging plan under § 76.11.'' 63 FR 25974. However, commenters were still concerned that the Administrator could, even after taking this into consideration, grant the relief over a utility's objections and prevent the utility from using an averaging plan that included the units for which the Administrator made the Phase II NO_X emission limitations inapplicable. In light of the utilities' concerns that proposed § 76.16 would actually reduce utilities' compliance flexibility, albeit under title IV, and prevent the use of averaging plans authorized under section 407(e), EPA has decided *not* to revise part 76 as proposed and is *not* adopting proposed § 76.16 as a final rule.

Suggestions by some commenters that, instead of adopting proposed § 76.16, EPA extend the compliance date under the Acid Rain Program for the Phase II NO_X emission limitations are rejected as outside the scope of this rulemaking. As acknowledged by commenters, that issue was raised in the rulemaking adopting the Phase II NO_X emission limitations, and the compliance deadline of January 1, 2000 set in that rulemaking was recently upheld by the courts in *Appalachian Power* v. *EPA*, 135 F.3d 791 (D.C. Cir. 1998). The SIP call rulemaking did not include any proposal to alter that date. On the contrary, EPA stated in the SIP call:

Obviously, in proposing a new 40 CFR 76.16, EPA is not requesting comment on any aspect of the December 19, 1996 final rule [i.e., the rule that set the Phase II NO_X emission limitations and that included an earlier, proposed version of § 76.16], including any issues addressed by the Court in *Appalachian Power.* 63 FR 25951.

Similarly, commenters' suggestions concerning other revisions to the Acid Rain NO_X Emission Reduction Program regulations (e.g., revisions to change the averaging provisions in the Acid Rain regulations to allow averaging among units that lack common owners or operators) are rejected as outside the scope of this rulemaking.

IX. Non-Ozone Benefits of NO_X Emissions Decreases

A. Summary of Comments

One commenter suggested that drinking water nitrate is not affected by atmospheric emissions and that the impacts of eutrophication are unknown, although no evidence was presented. Another commenter stated that EPA should estimate in the RIA the benefits of the SIP call with respect to the non-ozone impacts. One comment was received stating that EPA should not consider non-ozone benefits as justification for the proposed emission reductions.

B. Response to Comments and Conclusion

1. Drinking Water Nitrate

There is no disagreement that high levels of nitrate in drinking water is a health hazard, especially for infants. The contribution of atmospheric nitrogen (N) deposition to elevated levels of nitrate in drinking water supplies can be described as an evolving impact area. The Ecological Society of America has included discussion of this impact in a recent major review of causes and consequences of human alteration of the global N cycle in its Issues in Ecology series (Vitousek, Peter M., John Aber, Robert W. Howarth, Gene E. Likens, et al. 1997. Human Alteration of the Global Nitrogen Cycle: Causes and Consequences. Issues in Ecology. Published by Ecological Society of America, Number 1, Spring 1997). For decades, N concentrations in major rivers and drinking water supplies have been monitored in the United States, Europe, and other developed regions of the world. Analysis of these data confirms a substantial rise of N levels in surface waters, which are highly correlated with human-generated inputs of N to their watersheds. These N inputs are dominated by fertilizers and atmospheric deposition.

Increases in atmospheric N deposition to sensitive forested watersheds approaching N saturation would be expected to result in increased nitrate concentrations in stream water. This phenomenon has been documented in the Los Angeles, California area and has been well-established for areas in Germany and the Netherlands (Riggan, P.J., R.N. Lockwood, and E.N. Lopez, ''Deposition and Processing of Airborne Nitrogen Pollutants in Mediterranean-Type Ecosystems of Southern California'' Environmental Science and Technology, vol. 19, 1985). Stream water nitrate concentrations in watersheds subject to chronic air pollution in the Los Angeles area were two to three orders of magnitude greater than in chaparral regions outside the air basin.

2. Eutrophication

The EPA believes that the eutrophication problem associated with atmospheric nitrogen deposition is well established. The National Research Council recently identified eutrophication as the most serious pollution problem facing the estuarine waters of the United States (NRC, 1993). NO_X emissions contribute directly to the widespread accelerated eutrophication of United States coastal waters and estuaries. Atmospheric nitrogen deposition onto surface waters and deposition to watershed and subsequent transport into the tidal waters has been documented to contribute from 12 to 44 percent of the total nitrogen loadings to United States coastal water bodies. Nitrogen is the nutrient limiting growth of algae in most coastal waters and estuaries. Thus, addition of nitrogen results in accelerated algae and aquatic plant growth causing adverse ecological effects and economic impacts that range from nuisance algal blooms to oxygen depletion and fish kills.

3. Regulatory Impact Analysis

The EPA believes it is important to note the potential impacts of the rulemaking, including the substantial benefits to the environment of several non-ozone impacts. As described in the November 7 proposal, in addition to contributing to attainment of the ozone NAAQS, decreases of NO_X emissions will also likely help improve the environment in several important ways: (1) On a national scale, decreases in NO_X emissions will also decrease acid deposition, nitrates in drinking water, excessive nitrogen loadings to aquatic and terrestrial ecosystems, and ambient concentrations of nitrogen dioxide, particulate matter and toxics; and (2), on a global scale, decreases in NO_X emissions will, to some degree, reduce greenhouse gases and stratospheric ozone depletion. These benefits were also specifically recognized by OTAG, which in its July 8, 1997 final recommendations, stated that it ''recognizes that NO_X controls for ozone reductions purposes have collateral public health and environmental benefits, including reductions in acid deposition, eutrophication, nitrification, fine particle pollution, and regional haze.'' However, the benefits of some of these impacts are very difficult to estimate. Where possible, EPA provides estimates of the impacts of the rulemaking—both ozone and non-ozone—in the RIA.

4. Justification for Rulemaking

While EPA believes this information is important for the public to understand and, thus, needs to be described as part of the rulemaking and RIA, there should be no misunderstanding as to the legal basis for the rulemaking, which is described in Section I, Background, of this notice and does not depend on the non-ozone benefits. The non-ozone benefits did not affect the method in which EPA determined significant contribution nor the calculation of the emissions budgets.

X. Administrative Requirements

A. Executive Order 12866: Regulatory Impacts Analysis

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Agency must determine whether a 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.

In view of its important policy implications and potential effect on the economy of over $100 million, this action has been judged to be a ''significant regulatory action'' within the meaning of the Executive Order. As a result, the final rulemaking was submitted to OMB for review, and EPA has prepared a Regulatory Impact Analysis (RIA) entitled ''Regulatory Impact Analysis for the Regional NO_X SIP Call (September 1998).''

This RIA assesses the costs, benefits, and economic impacts associated with potential State implementation strategies for complying with this rulemaking. Any written comments from OMB to EPA and any written EPA response to those comments are included in the docket. The docket is available for public inspection at the EPA's Air Docket Section, which is listed in the **ADDRESSES** Section of this preamble. The RIA is available in hard copy by contacting the EPA Library at the address under ''Availability of Related Information'' and in electronic form as discussed above under ''Availability of Related Information.''

The RIA attempts to simulate a possible set of State implementation strategies and estimates the costs and benefits associated with that set of strategies. The RIA concludes that the national annual cost of possible State actions to comply with the SIP call are approximately $1.7 billion (1990 dollars). The associated benefits, in terms of improvements in health, crop yields, visibility, and ecosystem protection, that EPA has quantified and monetized range from $1.1 billion to $4.2 billion. Due to practical analytical limitations, the EPA is not able to quantify and/or monetize all potential benefits of this action.

B. Regulatory Flexibility Act: Small Entity Impacts

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (Pub. L. No. 104–121) (SBREFA), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis, unless it certifies that the proposed rule, if promulgated, will not have ''a significant economic impact on a substantial number of small entities.'' 5 U.S.C. 605(b). Courts have interpreted the RFA to require a regulatory flexibility analysis only when small entities will be subject to the requirements of the rule. *See, Motor and Equip. Mfrs. Ass'n* v. *Nichols*, 142 F.3d 449 (D.C. Cir. 1998); *United Distribution Cos.* v. *FERC*, 88 F.3d 1105, 1170 (D.C. Cir. 1996); *Mid-Tex Elec. Co-op, Inc.* v. *FERC*, 773 F.2d 327, 342 (D.C. Cir. 1985) (agency's certification need only consider the rule's impact on entities subject to the rule).

The NO_X SIP Call would not establish requirements applicable to small entities. Instead, it would require States to develop, adopt, and submit SIP revisions that would achieve the necessary NO_X emissions reductions, and would leave to the States the task of determining how to obtain those reductions, including which entities to regulate. Moreover, because affected States would have discretion to choose which sources to regulate and how much emissions reductions each selected source would have to achieve, EPA could not predict the effect of the rule on small entities.

For these reasons, EPA appropriately certified that the rule would not have a significant impact on a substantial number of small entities. Accordingly, the Agency did not prepare an initial RFA for the proposed rule.

For the final rule, EPA is confirming its initial certification. However, the Agency did conduct a more general analysis of the potential impact on small entities of possible State implementation strategies. This analysis is documented in the RIA. The EPA did receive comments regarding the impact on small entities. These comments will be addressed in the Response to Comment document.

This final rule will not have a significant impact on a substantial number of small entities because the rule does not establish requirements applicable to small entities. Therefore, I certify that this action will not have a significant impact on a substantial number of small entities.

C. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4) (UMRA), establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, 2 U.S.C. 1532, EPA generally must prepare a written statement, including a cost-benefit analysis, for any proposed or final rule that ''includes any Federal mandate that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more * * * in any one year.'' A ''Federal mandate'' is defined under section 421(6), 2 U.S.C. 658(6), to include a ''Federal intergovernmental mandate'' and a ''Federal private sector mandate.'' A ''Federal intergovernmental mandate,'' in turn, is defined to include a regulation that ''would impose an enforceable duty upon State, local, or tribal governments,'' section 421(5)(A)(i), 2 U.S.C. 658(5)(A)(i), except for, among other things, a duty that is ''a condition of Federal assistance,'' section 421(5)(A)(i)(I). A ''Federal private sector mandate'' includes a regulation that ''would impose an enforceable duty upon the private sector,'' with certain exceptions, section 421(7)(A), 2 U.S.C. 658(7)(A).

Before promulgating an EPA rule for which a written statement is needed under section 202 of the UMRA, section 205, 2 U.S.C. 1535, of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule.

The EPA has prepared a written statement consistent with the requirements of section 202 of the UMRA and placed that statement in the docket for this rulemaking. Furthermore, as EPA stated in the proposal, EPA is not directly establishing any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments. Thus, EPA is not obligated to develop under section 203 of the UMRA a small government agency plan. Furthermore, as described in the proposal, in a manner consistent with the intergovernmental consultation provisions of section 204 of the UMRA and Executive Order 12875, EPA carried out consultations with the governmental entities affected by this rule. Finally, the written statement placed in the docket also contains a discussion consistent with the requirements of section 205 of the UMRA.

For several reasons, however, EPA is not reaching a final conclusion as to the applicability of the requirements of UMRA to this rulemaking action. First, it is questionable whether a requirement to submit a SIP revision would constitute a federal mandate in any case. The obligation for a state to revise its SIP that arises out of sections 110(a) and 110(k)(5) of the CAA is not legally enforceable by a court of law, and at most is a condition for continued receipt of highway funds. Therefore, it is possible to view an action requiring such a submittal as not creating any enforceable duty within the meaning of section 421(5)(9a)(I) of UMRA (2 U.S.C. 658 (a)(I)). Even if it did, the duty could be viewed as falling within the exception for a condition of Federal assistance under section 421(5)(a)(i)(I) of UMRA (2 U.S.C. 658(5)(a)(i)(I)).

As noted earlier, however, notwithstanding these issues EPA has prepared the statement that would be required by UMRA if its statutory provisions applied and has consulted with governmental entities as would be required by UMRA. Consequently, it is not necessary for EPA to reach a conclusion as to the applicability of the UMRA requirements. The analysis assumes that states would adopt the control strategies that EPA assumed in its analyses underlying this action. The EPA further notes that in two related proposals also signed today—one concerning federal implementation plans if States do not comply with the SIP call and one concerning the petitions submitted to the Agency under section 126 of the CAA—EPA is taking the position that the requirements of UMRA apply because both of those actions could result in the establishment of enforceable mandates directly applicable to sources (including sources owned by state and local governments).

D. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of

Management and Budget (OMB) under the *Paperwork Reduction Act*, 44 U.S.C. 3501 *et seq.* An Information Collection Request (ICR) document has been prepared by EPA (ICR No. 1857.02) and a copy may be obtained from Sandy Farmer by mail at Regulatory Information Division; U.S. Environmental Protection Agency (2137); 401 M St., SW., Washington, DC 20460, by email at farmer.sandy@epa.gov, or by calling (202) 260–2740. A copy may also be downloaded from the internet at http://www.epa.gov/icr. The information requirements are not effective until OMB approves them.

The EPA believes that it is essential that compliance with the regional control strategy be verified. Tracking emissions is the principal mechanism to ensure compliance with the budget and to assure the downwind affected States and EPA that the ozone transport problem is being mitigated. If tracking and periodic reports indicate that a State is not implementing all of its NO_X control measures beginning with the compliance date for NO_X controls or is off track to meet its statewide budget by September 30, 2007, EPA will work with the State to determine the reasons for noncompliance and what course of remedial action is needed.

The reporting requirements are mandatory and the legal authority for the reporting requirements resides in section 110(a) and 301(a) of the CAA. Emissions data being requested in today's rule is not be considered confidential by EPA. Certain process data may be identified as sensitive by a State and are then treated as ''State-sensitive'' by EPA.

The reporting and record keeping burden for this collection of information is described below:

Respondents/Affected Entities: States, along with the District of Columbia, which are included in the NO_X SIP call.

Number of Respondents: 23.

Frequency of Response: annually, triennially.

Estimated Annual Hour Burden per Respondent: 269.

Estimated Annual Cost per Respondent: $7,140.00.

Estimated Total Annual Hour Burden: 6,197.

Estimated Total Annualized Cost: $164,190.00.

There are no additional capital or operating and maintenance costs for the States, along with the District of Columbia, associated with the reporting requirements of this rule. During the 1980s, an EPA initiative established electronic communication with each State environmental agency. This included a computer terminal for any States needing one in order to communicate with the EPA's national data base systems. Costs associated with replacing and maintaining these terminals, as well as storage of data files, have been accounted for in the ICR for the existing annual inventory reporting requirements (OMB # 2060–0088).

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An Agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR Part 9 and 48 CFR Chapter 15.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Office of Policy, Regulatory Information Division; U.S. Environmental Protection Agency (2137); 401 M St., SW.; Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th St., NW., Washington, DC 20503, marked ''Attention: Desk Officer for EPA.'' Comments are requested by November 27, 1998. Include the ICR number in any correspondence.

E. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

1. Applicability of E.O. 13045

The Executive Order 13045 applies to any rule that EPA determines (1) ''economically significant'' as defined under Executive Order 12866, and (2) the environmental health or safety risk addressed by the rule has a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children; and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. This proposed rule is not subject to E.O. 13045, entitled ''Protection of Children from Environmental Health Risks and Safety Risks (62 FR 19885, April 23, 1997), because it does not involve decisions on environmental health risks or safety risks that may disproportionately affect children.

2. Children's Health Protection

In accordance with section 5(501), the Agency has evaluated the environmental health or safety effects of the rule on children, and found that the rule does not separately address any age groups. However, the Agency has conducted a general analysis of the potential changes in ozone and particulate matter levels experienced by children as a result of the NO_X SIP call; these findings are presented in the Regulatory Impact Analysis. The findings include population-weighted exposure characterizations for projected 2007 ozone and PM concentrations. The population includes a census-derived subdivision for the under 18 group.

F. Executive Order 12898: Environmental Justice

Executive Order 12898 requires that each Federal agency make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minorities and low-income populations. The Agency has conducted a general analysis of the potential changes in ozone and particulate matter levels that may be experienced by minority and low-income populations as a result of the NO_X SIP call; these findings are presented in the Regulatory Impact Analysis. The findings include population-weighted exposure characterizations for projected ozone concentrations and PM concentrations. The population includes census-derived subdivisions for whites and non-whites, and for low-income groups.

G. Executive Order 12875: Enhancing the Intergovernmental Partnerships

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

Today's rule does not create a mandate on State, local or tribal governments. As explained in the discussion of UMRA (Section X.C), this rule does not impose an enforceable duty on these entities. Accordingly, the requirements of section 1(a) of Executive Order 12875 do not apply to this rule.

H. Executive Order 13084: Consultation and Coordination With Indian Tribal Governments

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

Today's rule does not significantly or uniquely affect the communities of Indian tribal governments. The rule applies only to certain States, and does not require Indian tribal governments to take any action. Moreover, EPA does not, by today's rule, call on States to regulate NO_X sources located on tribal lands. Accordingly, the requirements of section 3(b) of Executive Order 13084 do not apply to this rule.

The only circumstance in which the rule might even indirectly affect sources on tribal lands would be if the budget set for one or more of the 23 jurisdictions reflects assumed emissions reductions from NO_X sources on tribal lands located within the exterior boundaries of those States. The EPA is not aware of any such sources. However, to address the possibility that one or more of the State budgets reflects reductions from such sources, and because any such State generally would not have jurisdiction over such sources (see EPA's rule promulgated under CAA section 301(d), 63 FR 7254, February 12, 1998), EPA will consider any request to revise as appropriate the budget and base year 2007 emissions inventory for such a State, based on a demonstration that the State does not have authority to regulate those sources.

I. Judicial Review

Section 307(b)(1) of the CAA indicates which Federal Courts of Appeal have venue for petitions of review of final actions by EPA. This Section provides, in part, that petitions for review must be filed in the Court of Appeals for the District of Columbia Circuit if (i) the agency action consists of ''nationally applicable regulations promulgated, or final action taken, by the Administrator,'' or (ii) such action is locally or regionally applicable, if ''such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination.''

Any final action related to the NO_X SIP call is ''nationally applicable'' within the meaning of section 307(b)(1). As an initial matter, through this rule, EPA interprets section 110 of the CAA in a way that could affect future actions regulating the transport of pollutants. In addition, the NO_X SIP call, as proposed, would require 22 States and the District of Columbia to decrease emissions of NO_X. The NO_X SIP call also is based on a common core of factual findings and analyses concerning the transport of ozone and its precursors between the different States subject to the NO_X SIP call. Finally, EPA has established uniform approvability criteria that would be applied to all States subject to the NO_X SIP call. For these reasons, the Administrator also is determining that any final action regarding the NO_X SIP call is of nationwide scope and effect for purposes of section 307(b)(1). Thus, any petitions for review of final actions regarding the NO_X SIP call must be filed in the Court of Appeals for the District of Columbia Circuit within 60 days from the date final action is published in the **Federal Register**.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A ''major rule'' cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. § 804(2). This rule will be effective December 28, 1998.

K. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Pub. L. No. 104–113, section 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This final rulemaking sets forth a model trading program including environmental monitoring and measurement provisions that States are encouraged to adopt as part of their SIPs. If States adopt those provisions, sources that participate in the trading program would be required to meet the applicable monitoring requirements of part 75. In addition, this final rulemaking requires States that choose to regulate certain large stationary sources to meet the requirements of the SIP call to use part 75 to ensure compliance with their regulations. Part 75 already incorporates a number of voluntary consensus standards. In addition, EPA's proposed revisions to part 75 proposed to add two more voluntary consensus standards to the rule (see 63 FR at 28116–17, discussing ASTM D5373–93 ''Standard Methods for Instrumental Determination of Carbon, Hydrogen and Nitrogen in laboratory samples of Coal and Coke,'' and API Section 2 ''Conventional Pipe Provers'' from Chapter 4 of the Manual for Petroleum Measurement Standards, October 1988 edition). The EPA's proposed revisions to part 75 also requested comments on the inclusion of additional voluntary consensus standards. The EPA is finalizing some revisions to part 75 now, including the incorporation of two voluntary consensus standards, in response to comments submitted on the proposed part 75 rulemaking:

(1) American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992 (reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997; for § 75.19 and,

(2) Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed October 1992), for § 75.19.

These materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street NW, Washington, DC 20005–4070.

These standards are used to quantify fuel use from units that have low emissions of NO_X and SO_X.

The EPA intends to finalize other revisions to part 75 in the near future and address comments related to the proposed voluntary consensus standards and to additional voluntary consensus standards at that time.

Consistent with the Agency's Performance Based Measurement System, part 75 sets forth performance criteria that allow the use of alternative methods to the ones set forth in part 75. The PBMS approach is intended to be more flexible and cost effective for the regulated community; it is also intended to encourage innovation in analytical technology and improved data quality. The EPA is not precluding the use of any method, whether it constitutes a voluntary consensus standard or not, as long as it meets the performance criteria specified, however any alternative methods must be approved in advance before they may be used under part 75.

List of Subjects

40 CFR Part 51

Air pollution control, Administrative practice and procedure, Carbon monoxide, Environmental protection, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Transportation, Volatile organic compounds.

40 CFR Parts 72 and 75

Air pollution control, Carbon dioxide, Continuous emissions monitors, Electric utilities, Environmental protection, Incorporation by reference, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 96

Environmental protection, Administrative practice and procedure, Air pollution control, Nitrogen dioxide, Reporting and recordkeeping requirements.

Dated: September 24, 1998.

Carol M. Browner,

Administrator.

Appendix A to the Preamble—Detailed Discussion of Changes to Part 75

The following discussion addresses the comments received both on the SNPR (68 FR 25902) and the proposed part 75 revisions (68 FR 28032) that relate to the monitoring of NO_X mass emissions. In addition, it addresses the comments received on the excepted monitoring methodology for low mass emitting units that would apply to both units affected by title IV of the CAA and to units affected by a State or Federal NO_X mass reduction program that adopted or incorporated the requirements of this part.

I. NO_X Mass Monitoring and Reporting Provisions

Commenters raised four main issues with the proposed NO_X mass monitoring and reporting provisions in subpart H. The first issue has to do with the appropriate monitoring requirements necessary to support a NO_X mass monitoring program, particularly in light of the fact that many of the units that would be subject to a program based on Part 96 are not currently monitoring NO_X mass emissions. The second has to do with using a NO_X concentration CEMS and a flow CEMS to calculate NO_X mass. The third has to do with the requirement to report NO_X mass emissions year round even though the ozone season is only 5 months long. The final issue has to do with the requirement to have petitions for alternatives to part 75 be approved by both the state permitting authority and by EPA.

A. Background on Use of Part 75 to Monitor and Report NO_X Mass Emissions

Subpart H of the proposed part 75 rule set forth general monitoring and reporting requirements that sources subject to a State or Federal NO_X mass emission reduction program could incorporate or adopt into that program. Several commenters argued that it was inappropriate to require sources, who were not already required to meet the requirements of part 75, to meet those requirements for purposes of a state program.

Commenters who suggested that it was inappropriate to require a source that is not already subject to part 75 to meet the requirements of part 75 for purposes of a state program suggested that the State should decide what requirements the source needs to meet. The EPA agrees that this would be appropriate in the case of a program that only affected that state. For instance, if a State was developing a NO_X reduction program to address its own non-attainment problem, it would not be necessary to adopt requirements that were consistent across a larger geographic area. However, in a multi-state program, particularly a multi-state trading program which engages in interstate commerce like the one set forth in part 96, EPA believes it is necessary to account for emissions in a consistent manner across the whole region. This ensures that all sources that participate in the trading program account for their emissions in a consistent manner, ensuring both integrity in the trading program and a level playing field for all program participants. Therefore, EPA believes that it is necessary to create one set of consistent monitoring and reporting requirements that can be used for such a program. This is consistent with the way the Act mandated that a multi-state trading program be implemented under Title IV. It is also consistent with the approach taken in implementing other emissions standards, such as the new source performance standards that affect many states. This approach also makes it easier for states designing their programs since they would not have to reinvent the monitoring requirements in each case.

Commenters who suggested that part 75 did not provide enough flexibility focused on three areas: they suggested that other programs such as RECLAIM or the OTC trading program provided more flexible non-CEMS options for units that operated infrequently or had low NO_X mass emissions; they suggested that sources should be allowed to use predictive emissions monitoring systems (PEMS); and they suggested that sources should be allowed to use coal sampling and weighting to determine heat input.

The EPA believes that the flexibilities offered by part 75 are consistent with the type of flexibilities offered in RECLAIM and the OTC Program. RECLAIM requires CEMS on all units that emit more than 10 tons of any individual pollutant per year. The OTC Program requires CEMS on all units that do not qualify as peaking units that are larger than 250 mmBtu or serve generators greater than 25 MWs. Subpart H of part 75 allows non-CEMS alternatives for units that have emissions less than 50 tons per year of NO_X. If a unit is not required to report SO_2 and CO_2 for Acid Rain compliance, then the unit may use the low mass emissions provisions of Part 75 if its NO_X emissions are less than 50 tons per year. Part 75 also allows non-CEMS alternatives for units that qualify as peaking units. In both the OTC Program and part 75, a peaking unit is defined as a unit that has a capacity factor of no more than 10 percent per year averaged over a three year period and no more than 20 percent in any one year. The EPA believes that these options provide cost effective monitoring methodologies for small or infrequently used units.

While commenters who supported the use of PEMS and the use of coal sampling and weighting asserted that these methodologies would provide data equivalent to that provided by the methodologies in Part 75, none of the commenters provided any data to justify this claim. Therefore EPA is not adding specific requirements that would allow either of these methodologies. It should be noted that subpart E of part 75 does provide a means for a source to demonstrate that an alternative methodology such as PEMS or coal sampling and weighting is equivalent to CEMS. Subpart E of part 75 is consistent with Performance Based Measurement Systems criteria. Any source wishing to use an alterative methodology may petition the agency under subpart E of part 75.

B. Background on Use of a NO_X Concentration CEMS and a Flow CEMS to Calculate NO_X Mass

Subpart H of the proposed part 75 rule called for sources in the NO_X Budget Program to monitor NO_X emission rate in lb/mmBtu using a NO_X concentration monitor and a diluent monitor, and then to multiply this by heat input, calculated using a flow monitor and a diluent monitor. Under this proposal, sources would then calculate NO_X mass emissions by multiplying the hourly NO_X emission rate by the hourly heat input to obtain the pounds of NO_X emitted during the hour. The EPA also requested comment on whether it would be appropriate for sources in the NO_X Budget Program to use the NO_X concentration monitor and flow monitor without a diluent monitor to calculate NO_X mass emissions. This is analogous to the Acid Rain Program's current approach to monitoring SO_2 mass emissions.

Commenters recommended that the Agency require sources to determine NO_X mass emissions from pollutant concentration and stack gas volumetric flow. The commenters stated that this approach would be more accurate, more familiar to sources, and more consistent with the SO_2 mass emissions monitoring in the existing part 75.

The Agency agrees that using NO_X pollutant concentration and volumetric flow is an appropriate method for monitoring NO_X mass emissions. Today's final rule includes provisions in Subpart H and Section 8 of Appendix F of part 75 to allow sources to choose one of several options for monitoring and calculating NO_X mass emissions. Sources may monitor NO_X mass emissions by using either:

All Units

- A NO_X pollutant concentration monitor and a volumetric flow monitor, or a NO_X concentration monitor and a diluent monitor to calculate NO_X emission rate in lb/mmBtu, and a flow monitor and a diluent monitor to calculate heat input; or
- A NO_X concentration monitor and a diluent monitor to calculate NO_X emission rate in lb/mmBtu, and a fuel flow meter and oil or gas sampling and analysis to calculate heat input; or

Oil/Natural Gas Fired Units

- Peaking units may use NO_X to load correlation procedures from Appendix E of part 75 for NO_X emission rate, and a fuel flow meter and oil or gas sampling and analysis to calculate heat input; or
- Units with less than 50 tons of Nox and 25 tons of SO_2 may use emission rates multiplied by either the maximum rated heat input capacity of the unit or by the actual heat input of the unit which may be determined on a longer term basis than a single hour.

The EPA decided to allow sources several options so that they could use monitoring equipment that is already installed under part 75 to the greatest extent possible.

In implementing these options, a source would need to designate a primary approach to calculating NO_X mass emissions. For example, the designated representative of a coal-fired unit could choose to designate a primary monitoring approach under Option 1 (pollutant concentration monitor and diluent monitor, and diluent monitor and flow monitor). The designated representative could then use a (pollutant concentration monitor and flow monitor) as a backup monitoring approach. This would be useful for periods when the diluent monitor is not operating properly, where NO_X emission rate data in lb/mmBtu would not be available, but NO_X mass emission data in lb could still be available. The OTC NO_X Budget Program allows this approach (see docket A–97–35 item II-I–7).

In order to make monitoring as consistent as possible between the first two approaches for monitoring NO_X mass emissions using continuous emission monitoring systems (CEMS), EPA is making additional changes to part 75. First, the Agency is adding language in Section 8 of Appendix F that specifies the calculations for NO_X mass emissions using either approach. Second, EPA is requiring sources that use a NO_X pollutant concentration monitor and a flow monitor as the primary method for calculating NO_X mass emissions to substitute for missing NO_X pollutant concentration data using the same missing data procedures as for NO_X CEMS (lb/mmBtu) under §§ 75.31(c), 75.33(c) and Appendix C. Third, the Agency is establishing a relative accuracy testing requirement for NO_X pollutant concentration monitors that are used to calculate NO_X mass emissions independently of a NO_X CEMS (lb/mmBtu). The NO_X pollutant concentration monitors will need to meet a relative accuracy of 10.0 percent to pass the relative accuracy test audit (RATA). They will need to meet a relative accuracy of 7.5 percent to perform a RATA on an annual basis instead of a semi-annual basis. Because the vast majority of NO_X CEMS (lb/

mmBtu) and SO_2 pollutant concentration monitors routinely meet a relative accuracy of 7.5 percent or less, the Agency concludes that it will also be possible for a NO_X pollutant concentration monitor, which is part of a NO_X CEMS, to meet this standard. Fourth, EPA requires these sources to test their NO_X pollutant concentration monitor and flow monitor for bias. If the monitor is found to be biased low, then the source must either fix the monitor and retest it to show it is not biased, or apply a bias adjustment factor to hourly data. These changes to part 75 make monitoring consistent between the different monitoring approaches using CEMS, prevent underestimation of emissions, preserve monitoring accuracy, and take advantage of approaches already developed for other monitoring systems that will be familiar to sources.

The EPA decided to allow sources to calculate NO_X mass emissions using NO_X concentration and flow rate for several reasons:

- This approach would allow sources to remove bias due to the diluent monitor from calculations of NO_X mass emissions.
- Sources affected by the NO_X Budget Program, but not by the Acid Rain Program, such as industrial boilers, may be able to simplify their recordkeeping and reporting because they will not need to calculate or report NO_X emission rate in lb/mmBtu for each hour for the trading program.
- Sources will be able to maintain higher availability of quality-assured NO_X mass emission data, because they will not need to substitute missing data for purposes of NO_X mass emissions when data are not available from the diluent monitor.
- As the commenters suggested, this approach is more analogous to monitoring for SO_2 mass emissions in the Acid Rain Program.

Because this approach is already allowed under the OTC NO_X Budget Program, EPA already has accounted for this possibility in the electronic data reporting format and in its computerized Emission Tracking System.

For these reasons, the Agency believes that it is appropriate to allow sources the option of monitoring and calculating NO_X mass emissions using NO_X pollutant concentration and flow monitors.

Sources using this approach may still be required to install maintain and operate a diluent monitor to calculate heat input if required to do so by their state for purposes of obtaining data needed to support allocation of NO_X allowances.

C. Background on Year Round Reporting of NO_X Mass Emissions

The proposal would have required all units to report NO_X mass emissions on an annual basis rather than on an ozone season basis. One commenter noted that since the proposed SIP call would not require emission reductions outside of the ozone season it is not necessary to report NO_X mass emissions outside of the ozone season. The EPA agrees that solely for the purposes of an ozone program, it may not be necessary to report NO_X mass emissions outside of the ozone season except if a source wants to qualify for the low mass emissions provision. However the requirements of subpart H could be used to support NO_X mass emission reduction programs where reductions would be required annually. In addition, the monitoring and reporting requirements could be used to help consolidate other State or Federal reporting that would be required on an annual basis. Therefore in the final rule the requirements of subpart H have been modified so that they no longer require annual reporting of NO_X mass emissions, but rather defer to the State or Federal rule that is incorporating these requirements to define the applicable time period for reporting.

In addition a new section has been added to subpart H that details how the requirements of part 75, which are designed to be used annually, should be used if monitoring and reporting is being done for only part of the year.

Some of the most significant differences include:

- Owners and operators of units using the fuel sampling procedures in Appendix D must ensure that they have accurate fuel sampling information at the beginning of the ozone season. This requires either sampling the fuel tank itself before the start of the ozone season or meeting the requirements to sample fuel deliveries on a year round basis.
- Historical lookback periods for missing data periods only need to include data from the ozone season. However, if a monitor is out of control at the beginning of the season, historical data from seven months ago may represent significantly different operating conditions (e.g. fuel burned or use of control equipment). Therefore the AAR would have to certify that the operating conditions are representative of the previous years operating conditions. If the conditions are not representative, the standard missing data procedures could not be used. In this case maximum potential NO_X mass emissions would have to be substituted.
- The owner or operator of a unit must ensure that the monitors used for monitoring and reporting are in control. Since CEMS require ongoing quality assurance to ensure that they are operating properly, owners and operators of units that do not meet this requirement during the non-ozone season will have to recertify their monitors before the start of the ozone season.

D. Background on Requiring EPA and the State Permitting Authority to Approve Alternatives to Part 75

The proposal would have required owners and operators of units that are not subject to the requirements of title IV of the CAA that wish to petition for an alternative to any of the requirements of part 75 to petition both the state permitting authority and the Administrator. Several commenters suggested that approval of one or the other should suffice. Some of the commenters also noted that the requirements were different for units affected by title IV, who are only required to petition the Administrator.

The EPA agrees that the requirements for units affected by title IV and units not affected by title IV are inconsistent. Because of different requirements of the Act this inconsistency is necessary. The EPA has the sole authority to grant petitions to units affected by title IV under § 75.66 of part 75. If a State incorporates those monitoring requirements into its State rules, this still does not give it the authority to change or waive the monitoring requirements for a unit subject to title IV. However, recognizing that granting a petition affects the accounting of NO_X mass emissions for a State program, EPA does intend to work cooperatively with State agencies on petition requests that could affect monitoring and reporting of NO_X mass emissions.

For sources not affected by title IV that are complying with the requirements of subpart H because they have been adopted or incorporated into a State SIP, neither EPA nor the State has sole authority to approve a petition for an alternative. While the State does have the authority to set forth specific monitoring and reporting requirements in a SIP and submit those requirements for EPA approval, a State does not have the discretion to modify the SIP by changing or waiving those monitoring and reporting requirements without obtaining EPA approval. Likewise, EPA does not have sole authority to revise a SIP since the primary responsibility to develop and implement a SIP is granted to the States under the CAA. The EPA is however required by the CAA to review and approve or disapprove SIP revisions. Since a petition to change or waive unspecified requirements related to monitoring and reporting can not be approved as part of the original SIP approval process, EPA must be involved in any approvals of alternatives to the SIP.

In addition to the title I requirements for EPA to be involved in approval of petitions for alternatives to part 75, there are several other reasons that EPA needs to be involved. The first is that since EPA is administering the emissions data collection system under part 75, EPA must ensure that any changes to the reporting requirements can be handled by the emissions tracking system that EPA maintains. Secondly, in order to ensure the integrity of a multi-state market based system and to ensure that participants in the system are treated equitably, it is important to ensure that sources are treated equitably from State to State. Therefore, if interstate trading is taking place EPA clearly has a role in approving petitions for alternatives to ensure that sources are treated consistently from state to state when engaging in such interstate commerce.

II. Low Mass Emissions Excepted Monitoring Methodology

A. Background

In the January 11, 1993 Acid Rain permitting rule, EPA provided for a conditional exemption from the emissions reduction, permitting, and emissions monitoring requirements of the Acid Rain Program for new units having a nameplate capacity of 25 MWe or less that burn fuels with a sulfur content no greater than 0.05 percent by weight, because of the *de minimis* nature of their potential SO_2, CO_2 and NO_X emissions (see 58 FR 3593–94 and 3645–46). Moreover, in the January 11, 1993 monitoring rule, EPA allowed gas-fired and oil-fired peaking units to use the provisions of Appendix E, instead of CEMS, to determine the NO_X emission rate, stating that this was a *de minimis* exception. The EPA allowed this exception from the requirements of section 412 of the CAA because the NO_X emissions from these units would be extremely low, both collectively and individually (see 58 FR 3644–45). One utility wrote to the Agency, suggesting that the Agency consider further regulatory relief for other units with extremely low emissions that do not fall under the categories of small new units burning fuels with a sulfur content less than or equal to 0.05 percent by weight or gas-fired and oil-fired peaking units (see Docket A–97–35, Item II–D–31). The utility specifically suggested that the Agency consider an exemption, the ability to use Appendix E, or some other simplified methods which are more cost effective.

In the process of implementing part 75, other utilities also have suggested to EPA that it provide regulatory relief to low mass emitting units (see Docket A–97–35, Items II–D–29, II–E–25). These units might be low mass emitting because they use a clean fuel, such as natural gas, and/or because they operate relatively infrequently. Some utilities stated that they spend a great deal of time reviewing the emissions data when preparing quarterly reports for these units. Others argued that it would be important to reduce monitoring and quality assurance (QA) requirements in order to save time and money currently devoted to units with minimal emissions (see Docket A–97–35, Item II–E–25).

In response to the requests for simplified monitoring and recordkeeping requirements for units which both operate infrequently and have low mass emissions on May 21, 1998 the Agency proposed, under § 75.19 of part 75, changes to the monitoring requirements that would allow a new excepted methodology for low mass emission units. The proposed low mass emissions methodology would have allowed units which have emissions less than 25 tons of both NO_X and SO_2 to use a methodology with reduced monitoring, reporting and quality assurance requirements than the use of CEMS or either appendix D or E methodologies. The methodology proposed used a unit's maximum rated hourly heat input and generic defaults for SO_2, NO_X and CO_2 mass emissions. The proposed methodology was a less accurate methodology for determining emissions for SO_2, NO_X and CO_2 but would significantly reduce the burden on industry for these sources. The allowance of this methodology was justified using the *de minimis* individual and aggregate emissions represented by the units who would qualify for the methodology.

While the proposed methodology did not contain an explicit cutoff for CO_2, EPA believes that the limited applicability of the proposal ensured that emissions of CO_2 from units that would qualify to use the proposal was also *de minimis*. This is important, because under section 821 of the Act, the agency is also required to collect CO_2 emissions data from sources subject to title IV. This data is required to be collected ''in the same manner and to the same extent'' as required under title IV.

The Agency solicited comments on both the proposed methodology for determining emissions and the proposed applicability limits of 25 tons for both NO_X and SO_2 as well as any other comments related to the proposed low mass emission methodology. In reviewing the comments submitted on the proposal, the Agency noted that several commenters suggested the methodology was too restrictive and would only allow reduced monitoring to a limited number of units. The commenters suggested various methods for expanding applicability to the low mass emission methodology the most common which are; (i) remove the requirement for units to have both SO_2 and NO_X emissions of less than 25 tons and instead to allow units to use the methodology on a pollutant specific basis; (ii) increase the 25 ton limit for NO_X and SO_2 to 50, 100 or 250 tons; (iii) allow additional methods for calculating heat input; and (iv) allow the use of unit-specific NO_X emission rates. One other significant comment was received which indicated that the default values for NO_X emission rate in table 1b of proposed § 75.19 (c) could significantly underestimate emissions from certain types of units.

In response to the comments, which generally advocating the applicability of the low mass emissions methodology to more units, the Agency is adopting the proposed low mass emissions methodology with the following changes: (1) the NO_X applicability limit is being raised to 50 tons which will increase the number of units that can use the methodology; (2) units are being allowed an optional procedure for heat input which will increase the number of units that can use the methodology and provide more accurate emission estimates; (3) units are being allowed to use unit-specific NO_X emission rates determined through testing which will allow increased applicability and more accurate emissions estimates for NO_X; and (4) the values for NO_X emission rate in table 1b of proposed 75.19 (c) are being changed to prevent underestimation of emissions using the methodology.

B. Discussion of Low Mass Emissions Methodology

Today's new Low Mass Emissions methodology incorporates optional reduced monitoring, quality assurance, and reporting requirements into part 75 for units that burn only natural gas or fuel oil, emit no more than 25 tons of SO_2 and no more than 50 tons of NO_X annually, and have calculated annual

SO_2 and NO_X emissions that do not exceed such limits. Units that are not subject to Title IV of the Act and that are only subject to subpart H of part 75 are not required to meet the SO_2 limit to qualify to use the methodology. In addition, if allowed by their State, they may qualify as low mass emission units during the ozone season if they emit less than 25 tons of NO_X per ozone season.

A unit may initially qualify for the reduced requirements by demonstrating to the Administrator's satisfaction that the unit meets the applicability criteria in § 75.19(a). Section 75.19(a) requires facilities to submit historical actual (or projections, as described below) and calculated emissions data from the previous three calendar years demonstrating that a unit falls below the 25-ton cutoff for SO_2 and the 50 ton cutoff for NO_X. The calculated SO_2 mass emissions data for the previous three calendar years will be determined by choosing one of the two heat input options in § 75.19(c) and the appropriate emission rate from table 1a in § 75.19(c). The calculated NO_X mass emissions data for the previous three calendar years will be determined by choosing one of the two heat input options in § 75.19(c) and either the appropriate emission rate from table 1b in § 75.19(c) or a unit-specific NO_X emission rate as allowed under § 75.19(c). The data demonstrating that a unit meets the applicability requirements of § 75.19(a) will be submitted in a certification application for approval by the Administrator to use the low mass emissions excepted methodology.

For units that lack historical data for one or more of the previous three calendar years (including new units that lack any historical data), § 75.19(a) will require the facility to provide (1) any historical emissions and operating data, beginning with the unit's first calendar year of commercial operation, that demonstrates that the unit falls under the 25-ton cutoffs for SO_2 and the 50 ton cutoff for NO_X, both with actual emissions and with calculated emissions using the proposed methodology, as described below; and (2) a demonstration satisfactory to the Administrator that the unit will continue to emit below the tonnage cutoffs (e.g., for a new unit, applying the applicable emission rates and applicable hourly heat input, under § 75.19(c), to a projection of annual operation and fuel usage to determine the projected mass emissions).

For units with historical actual (or projections, as described above) emissions and calculated emissions falling below the tonnage cutoffs, facilities allowed to use the optional methodology in § 75.19(c) in lieu of either CEMS or, where applicable, in lieu of the excepted methods under Appendix D, E, or G for the purpose of determining and reporting heat input, NO_X emission rate, and NO_X, SO_2, and CO_2 mass emissions. The facility will no longer be required to keep monitoring equipment installed on low mass emissions units, nor will it be required to meet the quality assurance test requirements or QA/QC program requirements of Appendix B to part 75. Moreover, emissions reporting requirements will be reduced by requiring only that the facility report the unit's hourly mass emissions of SO_2, CO_2, and NO_X, the fuel type(s) burned for each hour of operation, and report the quarterly total and year-to-date cumulative mass emissions, heat input, and operating time, in addition to the unit's quarterly average and year-to-date average NO_X emission rate for each quarter. Owners and operators may also choose to report partial hour operating time and use the operating time to obtain a more accurate estimate of heat input determined using the maximum hourly heat input option. For units which use the optional long term fuel flow methodology for heat input the source will report hourly and cumulative quarterly and yearly output in either megawatts electrical output or thousands of pounds of steam. For units which use unit-specific NO_X emission rates determined through testing, reporting of the Part 75 Appendix E test results will be required. For units that have NO_X controls, data demonstrating that these controls are operating properly will have to be kept on site. Facilities will continue to be required to monitor, record, and report opacity data for oil-fired units, as specified under §§ 75.14(a), 75.57(f), and 75.64(a)(iii) respectively. Under § 75.14(c) and (d), however, gas-fired, diesel-fired, and dual-fuel reciprocating engine units will continue to be exempt from opacity monitoring requirements.

If an initially qualified unit subsequently burns fuel other than natural gas or fuel oil, the unit will be disqualified from using the reduced requirements starting the first date on which the fuel (other than natural gas or fuel oil) burned.

In addition, if an initially qualified unit subsequently exceeds the 25-ton cutoff for either SO_2 or the 50 ton cutoff for NO_X while using the adopted methodology, the facility will no longer be allowed to use the reduced requirements in § 75.19(c) for determining the affected unit's heat input, NO_X emission rate, or SO_2, CO_2, and NO_X mass emissions (unless at a future time the unit can again meet the applicability requirements based on the recent three years of data). Adopted § 75.19(b) allows the facility two quarters from the end of the quarter in which the exceedance of the relevant ton cutoff(s) occurred to install, certify, and report SO_2, CO_2, and NO_X data from a monitoring system that meets the requirements of §§ 75.11, 75.12, and 75.13, respectively.

Under the low mass emission excepted methodologies in § 75.19(c), a facility will calculate and report hourly SO_2, NO_X and CO_2 mass emissions by multiplying hourly unit heat input by an appropriate emission rate. Unit heat input is determined using one of two heat input methodologies, maximum rated hourly heat input or long term fuel flow; unit SO_2 and CO_2 emission rates are determined using generic defaults; and unit NO_X emission rate is determined using one of two methodologies, generic defaults or unit-specific NO_X emission rate testing.

Commenters raised three major issues, which have led EPA to modify its proposal. The three major issues raised were: (i) Should the proposed initial and ongoing applicability criteria of 25 tons of both NO_X and SO_2 be modified; (ii) was the proposed methodology for estimating emissions appropriate and, should other options for calculating emissions be allowed; and (iii) what should the reduced monitoring and quality assurance requirements be for these units?

1. Applicability Criteria

a. Approach. Based on the rationale described in the preamble to the May 12, 1998 proposal (63 FR 28037) and in the absence of significant adverse comment, the Agency is using both actual and calculated emissions as the basis for determining initial applicability.

b. Cutoff Limit for Applicability. Several commenters requested that the cutoff limit for applicability of the low mass emission provision be increased. These comments fell into two broad categories: (1) decouple the NO_X and SO_2 requirements and allow units which qualify as a low mass emissions unit for only one pollutant to monitor that pollutant using the low mass emissions methodology (see Docket A–97–35, Items, IV–D–24, IV–D–11, IV–D–23, IV–G–03, IV–D–20); and (2) raise the tonnage cutoff for NO_X and SO_2 (see Docket A–97–35, Items, IV–G–03, IV–D–24, IV–D–22, IV–D–23, IV–D–07, IV–G–02).

c. Determining the Criteria for Low Mass Emitters. Based on comments received the Agency believes that the low mass emission provision is appropriate for units which have low mass emissions because: (i) a unit has a low capacity factor usage or operates infrequently; or (ii) a unit has low mass emissions despite a relatively high capacity factor due to the small size of the unit. For these units, the cost of installing and maintaining CEMS would represent a relatively large portion of the total value of the electricity or steam produced by the unit. The Agency, also reasoned that the types of units identified above can use the excepted methodology without any significant risk to the environment or impairment of the Agency's ability to meet its obligations under the CAA.

The Agency also determined the types of units which were not appropriate candidates for use of the low mass emissions excepted methodology. In particular, the Agency has concerns about allowing large numbers of controlled units to use an estimation methodology such as the low mass emission methodology. Because many of these units have low mass emissions not because they operate infrequently, but rather because they have controls which reduce their emission rates, their continued low mass emissions is dependent on continued proper operation of the controls on the unit. The EPA believes that monitoring actual emission rates is necessary to ensure that installed emission controls are operating properly and that actual emissions remain low. On the other hand, EPA believes that it is appropriate to allow small or infrequently operated units with controls, such as peaking turbines with water or fuel injection, to use the low mass emissions provision. This is appropriate because as long as these units continue to limit their operation, their potential to emit still remains low, even if their controls are not working. Therefore, while EPA believes it is appropriate to allow small infrequently operated units with controls that have both low actual emissions and a low potential to emit (as long as they continue to operate at low levels), EPA does not believe that it is appropriate to allow controlled units that have large potential to emit if their controls are not operating properly to use this methodology.

The low mass emission excepted methodology is a new exception, in addition to the exceptions in the existing rule, from the requirement for a NO_X CEMS. The determination of whether individual and collective emissions covered by the exceptions from CEMS are *de minimis* must include consideration of emissions from both new and existing units that will qualify to use the new low mass emissions excepted methodology and also new and existing units that will qualify to use other exceptions from the NO_X CEM requirement, i.e. units using the existing appendix E excepted methodology and units with new unit exemptions under § 72.7.

The EPA has first considered the level of projected aggregate emissions determined to be *de minimis* for purposes of developing the new unit exemption promulgated in the January 11, 1993 Acid Rain permitting rule (58 FR 3593–94 and 3645–46). Aggregate emissions projected for units under the exemption were approximately 138 cumulative tons of SO_2 and 1934 cumulative tons of NO_X emitted per year from an estimated 170 new units which might qualify for the exception before the year 2000. As of September of 1998, 278 exemptions have actually been granted under the new unit exemption. The Agency estimates that the level of SO_2 and NO_X mass emissions from these units is 226 tons of NO_X and 3163 tons of SO_2. The Agency further believes that this group of excepted units will continue to increase at the current rate.

The EPA has also considered the level of emissions projected to be covered by appendix E. The EPA, in the January 11, 1993 Acid Rain monitoring rule, allowed gas-fired and oil-fired peaking units to use the provisions of appendix E, instead of CEMS, to determine the NO_X emission rate. The Agency stated that, even though this method was less accurate than CEMS, this was a *de minimis* exception because emissions from all units that qualify to use the appendix E reporting methodology were projected to be extremely low, the units did not have a NO_X compliance obligation, and the cost of installing and operating CEMS for these units would be high (see 58 FR 3644–45). The preamble to the January 11, 1993 rule estimated the emissions from oil and gas units which operated with a capacity factor of less than 10 percent to be 40,000 tons of NO_X per year. The Agency has analyzed existing appendix E units to determine the actual NO_X mass emissions reported by these units in 1997. This analysis indicates that in 1997 approximately 235 units used the appendix E methodology and had total emissions of approximately 11,000 tons of NO_X in 1997. (see Docket A–97–35, Items, IV–A–1).

The Agency has then considered what level of total NO_X emissions would be *de minimis* for all units that may be covered by *de minimis* exceptions from the requirement to use CEMS i.e. all units using the new unit exemption, appendix E, and the new low mass emissions methodology. The Agency maintains that a *de minimis* level of total NO_X emissions should not be more than one percent of the total NO_X emission inventory currently or in the future for all units. This approach is supported by the treatment of 40,000 tons of NO_X as *de minimis* in the January 11, 1993 rule preamble concerning appendix E, which is somewhat less than 1 percent of the total NO_X emissions estimated for 1993. However, the 40,000 tons of NO_X determined to be *de minimis* emissions in 1993 is not an appropriate *de minimis* level with regard to current and future levels of NO_X emissions. Several factors have increased the importance of monitoring lower levels of NO_X emissions including: (i) The new more stringent NAAQS for ozone (NO_X is an ozone precursor); (ii) title IV Phase II NO_X reductions which will reduce the total NO_X inventory; (iii) today's NO_X SIP call which may result in NO_X compliance obligations for gas-and oil-fired units and will reduce the NO_X emission inventory; and (iv) State and regional NO_X reduction programs, such as the OTC program, State RACT rules and the RECLAIM program in California, which result in NO_X compliance obligations for gas-and oil-fired units and reduced NO_X emission inventory. As a result, EPA views about 20,000 tons (close to 1 percent of projected NO_X emission inventory) as the *de minimis* level of NO_X emissions for the present and foreseeable future. Given that appendix E units and new unit exemption units currently account for about 14,100 tons of NO_X there is not a large margin left for establishing additional exception to the CEM requirements. The Agency has considered potential future growth in the number of units using the new unit exemption or appendix E in order to estimate what level of additional NO_X, SO_2 and CO_2 emissions might be appropriate to allow under the low mass emissions methodology. Taking account of the uncertainty inherent in such estimates EPA has set the applicability criteria for the low mass emission methodology so that the NO_X emissions covered by the methodology plus future growth in NO_X emissions covered by the other current *de minimis* exceptions (appendix E and the new unit exemption) will not exceed 5000 tons of NO_X per year in the future.

The Agency has analyzed SO_2, NO_X and CO_2 emissions and determined that, as long as the cutoffs for NO_X and SO_2 are coupled so that a unit must meet both the 50 tons of NO_X and 25 tons of

SO_2 limits, that SO_2, NO_X and CO_2 emissions under all exceptions from CEMS requirements will remain *de minimus.* Additionally decoupling the NO_X and SO_2 tons would allow only marginal simplification in monitoring while significantly complicating the low mass emissions methodology.

d. Determining the Tonnage Cutoffs for SO_2 and NO_X. The Agency has conducted a study of actual emissions data from 1997 quarterly reports under part 75 and evaluated potential tonnage cutoffs for SO_X and NO_X (see Docket A–97–35, Item IV–A–1). The analysis was based on the assumption that reported 1997 emissions of NO_X and SO_2 will be more representative of calculated emissions under the final low mass emissions methodology than they would have been under the proposed methodology. The assumption is considered valid because the final low mass emissions methodology allows more accurate heat input determination using long term fuel flow and the use of fuel and unit specific NO_X emission rates. These options allow more accurate emissions estimates than the proposed methodology would have. This differs from the analysis performed for the proposed low mass emission methodology which calculated emissions based on operating hours and maximum rated heat input.

Based on this analysis, EPA estimates that the existing Acid Rain affected sources that would qualify for the low mass emissions excepted methodology using a coupled 50 tons NO_X and 25 tons SO_2 limit would represent aggregate emissions of approximately 3100 tons of NO_X and approximately 260 tons of SO_2 in 1997 from 224 units. The analysis indicates that the applicability has been substantially increased in response to the comments received.

For the proposed 25 ton NO_X cutoff , which is the limiting factor for applicability in nearly all instances, the Agency has considered increasing the tons of NO_X to 50 tons, 75 tons, 100 tons, and 250 tons as suggested by various commenters. In its analysis, the Agency kept SO_2 at 25 tons, as discussed above.

The analysis showed that by increasing the NO_X limit to 250 tons coupled to 25 tons of SO_2, the aggregate tons of NO_X and SO_2 emitted by units which could currently qualify for the low mass emissions methodology increased to approximately 23124 tons NO_X and 4503 tons of SO_2; this is without considering potential future growth in the number of units that could qualify to use this exemption. Increasing the cutoff for NO_X to 250 tons could also allow many units with highly effective NO_X controls to use the low mass emissions provision. As explained previously, units with effective NO_X controls and high operating capacity should not use the low mass emission provision. The EPA concludes that with a 250 ton NO_X mass emissions applicability cutoff, the aggregate NO_X tons and percentage of inventory potentially covered by all the exceptions encompassed would easily exceed the *de minimis* level of emissions. The EPA has therefore, not adopted an increased cutoff limit for NO_X of 250 tons. Similarly, EPA concludes that an increased cutoff of 100 tons of NO_X would not be consistent with the type of source which the Agency has identified for use of the low mass emission excepted methodology or fit under the *de minimis* level of emissions defined for NO_X by the Agency. At the 100 ton cutoff for NO_X coupled to a 25 ton cutoff for SO_2 the aggregate NO_X emissions are 8841 tons of NO_X and 540 tons of SO_2 from 408 qualifying units. The analysis performed by the Agency indicates that 50 tons of NO_X coupled to 25 tons of SO_2 is the appropriate cutoff limit for applicability to the low mass emissions excepted methodology. The approximate aggregate emissions of 3600 tons of NO_X and 250 tons of SO_2 from 240 sources allows the appropriate type of units to use the provisions without great potential of exceeding a de-minimus level of NO_X emissions. In choosing the 50 ton NO_X mass emission cutoff limit over other limits, the Agency evaluated the available data and applied the following criteria: (1) The NO_X tons limit should allow reduced monitoring for the units which EPA determined were appropriate candidates for the low mass emissions provisions during the rulemaking process, namely units with low mass emissions both collectively and individually due to low operating levels or small size but not highly controlled units which operate at higher levels; (2) the NO_X tons limit should allow reduced monitoring for a group of units consistent with the level of *de minimis* emissions inventory for all exceptions for the CEMS requirement; and (3) the limit should not jeopardize the Agency's ability to effectively fulfill its obligations under of the CAA.

From the analysis performed, the Agency has demonstrated that increasing the 25 ton limit for SO_2 would result in allowing few additional sources the option to use the low mass emissions methodology. For example at a coupled 50 tons of NO_X and 25 tons of SO_2 increasing the SO_2 tonnage cutoff to 50 tons would allow only 7 additional units to use the methodology. The additional units identified all combusted oil as the primary fuel which has a very high sulfur content in comparison to natural gas. While natural gas fired units could easily increase operations without substantial increases in SO_2 emissions oil fired units could not. The additional units which burn oil and qualify are considered inappropriate candidates for use of the low mass emission provision. Therefore, the Agency has chosen to leave the tonnage limit at the proposed level of 25 tons for SO_2. Leaving the cutoff for applicability for SO_2 at 25 tons also reflected the opinion of commenters who suggested raising only the NO_X tonnage.

When considering the size cutoffs, EPA also took into account both the effect that the use of this methodology could have on other regulatory actions and the effect that other regulatory actions could have on the number of units and percentage of emissions that could be covered by units using this methodology. In particular, EPA was concerned about the SIP call. Units that could qualify to use the low mass emission methodology do not have a NO_X emission limit under title IV. However, under the SIP call, units that are using the monitoring requirements of part 75 to comply with the requirements of the SIP call, including units that could qualify to use the low mass emitter methodology, would have an emission limit. As explained in Section VI.A.2.c and VII.D.3 of today's preamble, EPA believes that it is important that large sources of NO_X mass emissions accurately account for their emissions. Because EPA is expecting substantial reductions in NO_X emissions from the title IV phase II NO_X emission rate limits, the SIP call and other similar programs, EPA believes that even if the total NO_X emissions coming from units that could qualify for the low mass emitter methodology does not increase, the percentage of emissions coming from these units will increase. The EPA also believes that the incentives provided under a trading program could encourage smaller oil and gas fired units that may not currently qualify under the low mass emission methodology to install controls. As a result, this could increase the number of units, the amount of emissions and the percentage of emissions that could be accounted for by units using this methodology. EPA believes that the 50 ton cutoff is adequate to ensure that emissions from units that qualify for the low mass emitter methodology are de-minimis today. In the future however, growth in the number of units may cause the level of NO_X, SO_2 or CO_2 emissions from units qualifying for and using the new unit exemption, appendix E, the low mass emitter provision and other programs such as the SIP call to exceed a de-minimis level and the agency reserves the right to re-assess any and all of these exceptions in the future if the need arises.

e. Decoupling NO_X and SO_2. In order to qualify for the low mass emissions excepted methodology, the applicability criteria require a unit to meet annual tonnage cutoffs of 25 tons for SO_2 and 50 tons for NO_X. The EPA has considered whether the excepted methodology should be available on a pollutant specific level so that, for example, a unit which falls below the tonnage cutoff for SO_2 but not for NO_X could use the excepted methodology under § 75.19 to measure SO_2 emissions but use a NO_X CEM or the excepted methodology under appendix E, where applicable, to measure NO_X emissions. All analysis the Agency has done indicates that the NO_X tonnage is the limiting factor for greater than 90 percent of all units when applicability is for units to meet a coupled 50 ton NO_X and 25 ton SO_2 limit (see Docket A–97–35, Items, II–A–10, IV–A–1) For example, approximately 20 units were identified which would potentially be qualified to use the low mass emission methodology for a 50 tons of NO_X cutoff who would not meet the 25 tons of SO_2 cutoff and therefore be disqualified from using the methodology. Conversely, the agency's analysis indicated that leaving the tonnage cutoff for SO_2 mass emissions at 25 tons and decoupling NO_X and SO_2 would potentially allow approximately 650 units in the program to use the low mass emissions methodology for SO_2 (see Docket A–97–35, Items, II–A–10, IV–A–1). In particular allowing decoupling could impair the Agency's ability to collect data on CO_2 emissions as required under the CAA section 821. The analysis performed by the Agency indicates, that even with a 25 ton limit on SO_2, 652 units could qualify for the use of the low mass emissions methodology for SO_2 only. The 652 units identified represent approximately 10 percent of the total program heat input and greater than 6 percent of the total program CO_2 emissions. If a unit which qualified for the use of only SO_2 were allowed to use the low mass emissions methodology for CO_2 the result could be overestimation of CO_2 emissions from a sizeable percentage of the total CO_2 inventory. Future decisions based on such data might draw incorrect conclusions.

For the reason stated above, if a unit were allowed to qualify for a single pollutant the unit would be allowed to use the low mass emissions methodology for that pollutant only and not for CO_2 or heat input estimations. Therefore, no practical benefit for industry would result from decoupling SO_2 and NO_X. Decoupling would not be particularly beneficial because qualifying for one pollutant only allows only minimal monitoring reductions when CO_2 and heat input are not simplified. In addition decoupling would dramatically increase the complexity of the low mass emissions methodology. The added complications which would benefit a limited number of sources in only a limited way would increase the time and effort needed for all other sources in understanding and implementing the methodology. The agency concludes that the burden from the increased rule complexity outweighs the benefit from decoupling SO_2 and NO_X.

The following discussions further explain the Agencies position.

One of the prime benefits of the low mass emissions excepted methodology will be the simplified reporting which will require less time and a less sophisticated Data Acquisition and Handling System (DAHS). In particular, the need for a DAHS that could calculate substitute data using the current missing data algorithms will be removed because there are no missing data algorithms for the low mass emissions excepted methodology. If the excepted methodology is only applied to one of the pollutants, much of the benefit would be negated because the DAHS will still need to be capable of calculating substitute data for the measured pollutant and close to the full quarterly report would still be required.

Another prime benefit of the low mass emissions excepted methodology will be the reduction of monitoring and quality assurance requirements. A unit which would qualify for SO_2 only would still need to determine CO_2 mass emissions using a fuel flow meter. Additionally the units which would qualify are primarily gas fired units which would be allowed to use appendix D for SO_2. In this case no benefit is allowed by using the low mass emissions methodology. A limited number of oil fired units would be granted some reduced sampling requirements.

The agency's analysis indicates that most units which would qualify for NO_X only can use the excepted methodology under appendix E.

As stated before the analysis indicates that the benefits of decoupling are outweighed by the complications of allowing decoupling.

f. The use of the Low Mass Emitter Methodology with fuels other than oil and natural gas. One commenter suggested that the applicability should be expanded to include other fuels including low sulfur solid fuels such as wood. EPA disagrees with the commenter who claims that the methodology should be irrespective of fuel type. The fuel type is an integral part of the emissions calculations and insures that emissions are not underestimated. The Agency does not have, and the commenter did not provide, sufficient data to justify including wood fired solid fuel units into the low mass emission methodology. The limited data EPA has does not provide assurance that wood is always low in sulfur or that it results in low mass emissions of NO_X. The use of AP 42 emission factors was considered but rejected based on the possibility of underestimation of NO_X emissions using the AP 42 factors, as stated in the January 11, 1993 rule preamble at 58 FR 364445. If EPA is provided with information addressing this issue in the future, EPA will consider expanding the applicability to units that burn wood in the future.

2. Method for Determining Emissions

On May 21, 1998 the Agency proposed a low mass emissions methodology which used maximum rated heat input as the only heat input option and default emission rates for SO_2, NO_X, and CO_2. The Agency requested comment on whether this methodology was appropriate or whether an alternate approach should be adopted for low mass emitting units. In response, several commenters suggested changing the method for determining emissions. One commenter suggested allowing the use of unit-specific NO_X testing (see Docket A–97–35, Item IV–D–20). Another commenter suggested that long term fuel flow heat input be allowed as an alternative to the proposed maximum rated heat input (see Docket A–97–35, Item IV–D–13). Two other commenters suggested that further unspecified options be allowed for determining heat input (see Docket A–97–35, Items, IV–D–03, IV–G–02). Additionally several commenters suggested that the reduced monitoring under the low mass emission methodology was being limited to too few sources (see Docket A–97–35, Items, IV–D–07, IV–D–22, IV–D–23, IV–D–24, IV–G–03). Other commenters made the general suggestion that part 75 should be more consistent with the monitoring requirements of the OTC NO_X Budget Program. Finally the Agency received both comments and data which indicated that for uncontrolled gas fired turbines combusting both oil and gas the default emission rates for NO_X in proposed table 1b of § 75.19 (c) were potentially substantial underestimations of actual emission from these types of units (see Docket A–97–35, Item IV–D–22). Further analysis by the Agency provided supporting evidence that the emission rates in proposed 75.19 (c), table 1b, might underestimate emissions significantly for gas and oil fired turbines (see Docket A–97–35, Item IV–A–1). In response to these comments which reflected a general desire to expand the applicability of the low mass emission methodology through changes in both the heat input and NO_X emissions methodology, and in light of no negative comments reflecting opposition to allowing the low mass emission methodology, the Agency began analysis of what changes in the methods for determining heat input and NO_X emissions could be allowed without risk of underestimation of emissions, or negative environmental consequences. The Agency received no comments on changing either the SO_2 or CO_2 methods for determining emissions and therefore did not attempt to change these methodologies.

a. Adoption of the Proposed Methodology. In the proposal, the Agency considered several methods for determining the estimated emissions as the basis for applicability of the reduced monitoring and reporting excepted methodology. For each of the methods considered, rather than using actual measured sulfur and carbon values, CO_2, SO_2, and flow CEM readings, NO_X CEM readings, or NO_X values from an Appendix E NO_X-versus-heat input correlation, a facility will calculate the unit's emissions based on an emission rate factor and one of two heat input methodologies. Since the units that will qualify for the excepted methodology will still be accountable for reporting emissions to the Agency and surrendering allowances based on those emissions, where applicable, the emissions estimations will not just be used to determine if the unit qualifies under the exception; the reported estimations will also be used to determine compliance. Prior to the proposal, some industry representatives suggested that facilities would be willing to use a conservative emission estimate, such as a maximum potential emission rate times the maximum heat input, if it would allow them to save time and money currently spent on monitoring and quality assurance (see Docket A–97–35, Items II–D–30, II–D–43, II–D–45, II–E–13, and II–E–25). The Agency decided it was appropriate to retain the proposed methodologies of maximum rated heat input and default SO_2, NO_X and CO_2 emission rates for the final rule. It was also decided to allow increased applicability of the low mass emissions methodology through optional unit-specific NO_X emission rate determinations and the use of an optional heat input methodology (e.g., long term fuel flow).

b. Change in Table 1b, Default NO_X Emission Rates. In deciding to retain the proposed low mass emission methodology as part of the final rule the Agency had to consider that some values for NO_X emission rate in proposed table 1b of § 75.19 (c) had a high potential for underestimating emissions in at least some cases. The Agency acknowledged that increasing the default NO_X emission rates in table 1b of § 75.19 (c) will reduce the number of units allowed to use the low mass emissions methodology. Based on the comments received (see Docket A–97–35, Item IV–D–20) and to both allow increased applicability and increase the default rates to an appropriate level, the use of NO_X testing to determine units-specific NO_X emission rates will be allowed as an alternative option to using the default NO_X emission rates in table 1b of § 75.19 (c). Allowing the option of unit-specific NO_X emission rates will generate more realistic NO_X emission rates than the default NO_X emission rates in table 1b of § 75.19 (c) and will maintain some of the simplicity of the NO_X mass methodology from the low mass emissions methodology proposal.

The next issue was deciding which default NO_X emission rates in table 1b of § 75.19 (c) to raise and what level to raise the defaults to. As a first consideration the Agency noted that the default NO_X emission rates in table 1b of proposed § 75.19 (c) should be increased to the level at which it will be highly unlikely that any unit that performed testing will have a higher emission rate than the default. In this case, a source might opt to use a default which would knowingly underestimate emissions under certain operating conditions. Since all of the defaults used in table 1b of proposed § 75.19 (c) were based on the 90th percentile it is very likely that some units would have a higher emission rate than the NO_X emission rates in table 1b of proposed 75.19 (c). For this reason, all of the NO_X emission rate values in proposed table 1b were increased to a level which will ensure that units will not have higher tested emission rates than the default rates in Table 1b. A commenter suggested that these provisions be more consistent with the provisions for the Ozone Transport Commission (OTC), NO_X Budget Program (see Docket A–97–35, Item IV–D–13). The default emission rates the Agency decided to adopt are the default rates used in the OTC NO_X Budget Program (see Docket A–97–35, Item II–I–7). In the OTC NO_X Budget Program, units similar in emission characteristics to those who will qualify as low mass emission units under today's rule have the option of unit specific testing or unit generic default OTC NO_X emission rates. In the OTC NO_X Budget Program units have chosen both options based on owner or operator preference. Finally, adopting the NO_X Budget Program defaults creates consistency among programs which is a supplementary benefit.

c. Unit-Specific NO_X Emission Rate Testing. In considering the options for unit-specific NO_X emission rate testing the Agency had to address several concerns, including the following: (1) Units with NO_X controls who performed unit specific testing with the controls operating might have the potential to grossly underestimate emissions if the controls failed; (2) what sort of test would be appropriate for determining the low mass emissions methodology fuel -and-unit-specific NO_X emission rate; (3) how long a period should a source be allowed to use the unit-specific NO_X rate once determined through testing; (4) under what conditions should a source be required to retest for a new unit-specific NO_X emission rate; (5) for sources with historical reported emissions data using CEMS under part 75, what historical NO_X emission rate value might be appropriate for use in lieu of an initial test; and (6) if a source owns multiple identical units, should representative testing be allowed at some of the units to represent all units.

The first issue resolved was the use of Appendix E of Part 75 procedures for determination of a unit-specific NO_X emission rate for each fuel combusted by the unit. The unit-specific NO_X emission rate selected, for each fuel tested, will be the highest recorded NO_X emission rate from the test at any test load or operating condition multiplied by 1.15. Units which combust multiple fuels can use, for different fuels, either a unit-specific NO_X rate determined through testing or use the default NO_X emission rates listed in table 1b of § 75.19 (c). For example, a unit which primarily combusts oil but occasionally combusts natural gas could determine a unit-specific NO_X emission rate for oil through Appendix E testing and use the default NO_X emission rate from table 1b of § 75.19 (c) for gas. For hours in which a unit combusts multiple fuels in one hour, the unit must use the highest emission rate for that hour for all fuels combusted. In conducting the Appendix E test, the requirement for monitoring heat input to the unit during the test is removed as it is an unnecessary burden. The multiplier of 1.15 is required because of Agency analysis which indicates that appendix E testing is not representative of emissions at a given load at all times. In particular, the analysis of units with NO_X emission rate CEMS indicated that the NO_X emission rate can vary an average of 15 percent at a given load during different periods of operation. The most probable cause of the difference noted is variations in atmospheric moisture content. The agency notes that units which do appendix E testing during hot humid conditions would likely underestimate emissions during cooler less humid conditions. The Appendix E test was chosen for several reasons including: (1) many current Acid Rain sources which might qualify for the low mass emissions methodology already have performed Appendix E testing and will be allowed to use their historical Appendix E test data to determine a unit-specific NO_X emission rate without further requirements; (2) the requirements of Appendix E testing are already familiar to sources and contractors who may perform the testing, thus reducing further burden imposed by requiring new testing methodologies; (3) The use of the Appendix E test and the multiplier of 1.15 ensures that a unit uses a NO_X emission rate which will not underestimate emissions at any normal operating condition.

Once the Appendix E test was chosen, the use of a five year testing frequency was deemed appropriate as it matched the current Appendix E test period and matches the current permit renewal cycle.

A special provision was included in the low mass emission methodology to allow units with historical CEMS NO_X emission rate data to determine a unit-specific NO_X emission rate from historical certified CEMS data. Under this provision a unit will analyze historical data from hours in which a unit combusted a particular fuel. The analysis will determine the unit-specific NO_X emission rate which will yield a 95 percent confidence that the unit will not emit at a higher NO_X emission rate while combusting the fuel being analyzed. The Agency also considered using the highest NO_X rate from historical data but reasoned that the large data sets used to generate the unit- and fuel-specific emission rate would contain outliers which would make the procedure unfeasible for most units. The Agency considered several options for units which used NO_X controls and wished to use unit-specific NO_X emission rates determined through Appendix E testing. One option was to allow units to test with the NO_X control devices not operating or minimized. This option was rejected for the following two reasons: (1) the Agency does not support adopting a rule which would require sources to operate in a manner that would increase emissions; and (2) some sources which have controls are not allowed to operate when the controls are not operating by permit restrictions and these units would be disallowed from using the low mass emission methodology unfairly. The Agency also considered not allowing units with NO_X emission controls to use the low mass emission methodology. While the Agency does believe that it is *not* appropriate to include large controlled units, the Agency does feel it is appropriate to allow infrequently used controlled units, such as peaking turbines with steam or water injection to benefit from the reduced requirements of this methodology (as further explained above). Therefore this solution was rejected as excluding many units for which the Agency believes it is appropriate to allow reduced monitoring from more accurate and more costly monitoring requirements.

The Agency also considered allowing only units with certain types of controls to use the low mass emission methodology. This approach was rejected because the Agency does not, at this time, have the necessary information or expertise to make an appropriate determination on this approach.

The Agency also considered allowing units to determine a unit-specific NO_X emission rate using NO_X controls with no restriction. In analyzing this option, the Agency identified several units which would qualify for the low mass emission methodology based on the applicability criteria of 50 tons of NO_X and 25 tons of SO_2 which the Agency did not believe were appropriate to use the low mass emission methodology. The units identified had advanced control technologies such as selective catalytic reduction (SCR) and burned low sulfur fuels such as natural gas. The units identified consistently reported hourly emission rates as low as 0.01 lb/mmBtu as compared to uncontrolled rates which are generally 10 to 100 times higher for these units. The best method of continued assurance that a unit's NO_X controls are operating is monitoring with a NO_X CEMS. These units also operated during more than half the hours of a year at an average heat input of greater than 1000 mmBtu/hr. While, for these units, the potential to underestimate SO_2 emissions was low, the potential to grossly underestimate NO_X mass emissions using the low mass emission methodology was much greater. For this reason, the Agency rejected allowing a controlled unit to use a single emission rate determined through Appendix E testing once every five years while NO_X controls were operating.

The methodology the Agency adopted in this rule was the use of a lower limit of 0.15 lb/mmBtu for a unit-specific NO_X emission rate for units which opt to perform unit-and fuel-specific Appendix E testing while controls are operating. For units with NO_X emission controls, which perform unit-specific NO_X emission rate testing and whose test results in a NO_X emission rate of less than 0.15 lb/mmBtu, the source will use the NO_X emission rate limit of 0.15 lb/mmBtu for the unit-specific NO_X emission rate instead of the lower tested NO_X emission rate. Units with NO_X emission controls who perform unit-specific NO_X emission rate testing and whose results from the testing indicate a NO_X emission rate of higher than 0.15 lb/mmBtu will be required to use the higher NO_X emission rate as the fuel- and unit-specific NO_X emission rate. In considering this approach the Agency considered using the lowest NO_X emission rate proposed in 75.19 (c), Table 1b, of 0.172 lb/mmBtu, as well as 0.15 lb/mmBtu, 0.1 lb/mmBtu and 0.05 lb/mmBtu as lower limits for NO_X emission rate. The proposed gas fired turbine emission rate was 0.172 lb/mmBtu. Using 0.172 lb/mmBtu as the lower limit for controlled units was rejected as being an arbitrary choice based on a number representative of only a single class of units and not representative of the difference between controlled and uncontrolled units. An analysis was performed to determine a reasonable lower cutoff between controlled and uncontrolled units which would allow controlled units to qualify for the reduced monitoring provisions of the excepted low mass emission methodology without serious risk of underestimation of emissions. The analysis indicated that a minimum allowable emission rate of 0.15 lb/mmBtu for controlled units best allowed for fairness between controlled and uncontrolled units and insured that very large units with high operating hours and extremely low NO_X emission rates will not be allowed to use the low mass emission excepted methodology. The Agency's decision was also heavily influenced by the desire to insure that overall, the emission rate chosen would insure that aggregate emissions of controlled units were indeed *de minimis.* The Agency notes that the lower limit of 0.15 lb/mmBtu NO_X emission rate, when coupled with the annual limit of 50 tons of NO_X, effectively limits the annual heat input of units using the methodology to 666,666 mmBtu annual heat input. Analysis done by EPA found this to be an appropriate limit on heat input for the low mass emission excepted methodology (see Docket A–97–35, Item IV–D–20). In general, the lower emission rate limit for controlled units, and uncontrolled units inability to achieve such low rates, combines to limit the low mass emission methodology to the infrequently operated low mass emitting units the Agency was targeting for use of the provision in today's new rule.

Controlled units that use this methodology are also subject to additional requirements. The owner or operator of the unit must ensure that the controls are being operated in the same manner that they were operated during the unit specific testing. Documentation of this must be kept on site. Any hour that the controls are not operating properly, the owner or operator must use the default emission rates for NO_X in table 1.b of § 75.19 (c), rather than the emission rate determined through unit specific testing.

Based on experience gained working with the OTC in the implementation of the OTC NO_X budget program, EPA believes that many of the units that may benefit from this new excepted monitoring methodology are banks of identical small emission turbines. The OTC has allowed these units to do representative sampling at a number of units rather than requiring testing at all of the units. While none of the commenters mentioned this specific flexibility of the OTC NO_X Budget program, EPA believes that this is one of the flexibilities that commenters who suggested adopting some of the methodologies that the OTC has allowed for smaller units were referring to. Therefore this final rule contains a similar allowance for identical units. If the owner or operator of a number of units that are located at one facility can demonstrate that those units are identical, this final rule will allow emission rate testing to be done at a representative number of units.

d. The Adoption of Maximum Rated Heat Input as Proposed. While several commenters suggested allowing alternative methods for determining heat input, none directly suggested replacing or altering the basic heat input approach as an option (as described in 68 FR 28037–8). For this reason the maximum rated hourly heat input option from the proposal was retained as a less accurate but acceptable approach.

e. Long Term Fuel Flow for Heat Input Determination. To allow greater flexibility to units under the low mass emissions methodology and to allow more realistic estimations of heat input as suggested by several commenters the Agency is allowing the use of long term fuel flow measurements to determine heat input to low mass emitting units as described earlier. The Agency chose to adopt this methodology for the following reasons: (1) The methodology allows more accurate measurements of total heat input into a unit over the reporting period than the use of maximum rated hourly heat input; (2) the methodology has proven to be usable by sources who have chosen to use a similar method in the Ozone Transport Commission, NO_X Budget Program; and (3) the methodology is straightforward and is optional for sources which might be excluded from using the low mass emissions methodology if allowed to use maximum rated hourly heat input only.

3. Reduced Monitoring and Quality Assurance Requirements. As discussed above, today's rule allows facilities to use a maximum rated hourly heat input value and an emission rate factor to determine the mass emissions from a low-emitting unit for each hour of actual operation. This approach involves no actual emissions monitoring and minimal quality assurance activities. Instead, the facility will only need to keep track of whether the unit combusted any fuel for a particular hour and what type of fuel was combusted. In this way, the revised rule significantly reduces the burden on affected facilities, while still ensuring that emissions are not under reported.

For owners or operators which opt to use either the long term fuel flow methodology or a fuel-and unit-specific NO_X emission rate, some additional quality assurance will be required. As these two options under the low mass emission methodology are not required and will allow units which would not otherwise qualify to use the low mass emission methodology, the additional quality assurance requirements are not burdensome to the sources using either long term fuel flow or unit-specific NO_X emission rates.

For the reasons set forth in the preamble, parts 51, 72, 75, and 96 of chapter I of title 40 of the Code of Federal Regulations are amended as follows:

PART 51—REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

1. The authority citation for part 51 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart G—Control Strategy

2. Subpart G is amended to add §§ 51.121 and 51.122 to read as follows:

§ 51.121 Findings and requirements for submission of State implementation plan revisions relating to emissions of oxides of nitrogen.

(a)(1) The Administrator finds that the State implementation plan (SIP) for each jurisdiction listed in paragraph (c) of this section is substantially inadequate to comply with the requirements of section 110(a)(2)(D)(i)(I) of the Clean Air Act (CAA), 42 U.S.C. 7410(a)(2)(D)(i)(I), because the SIP does not include adequate provisions to prohibit sources and other activities from emitting nitrogen oxides (''NO_X'') in amounts that will contribute significantly to nonattainment in one or more other States with respect to the 1-hour ozone national ambient air quality standards (NAAQS). Each of the jurisdictions listed in paragraph (c) of this section must submit to EPA a SIP revision that cures the inadequacy.

(2) Under section 110(a)(1) of the CAA, 42 U.S.C. 7410(a)(1), the Administrator determines that each jurisdiction listed in paragraph (c) of this section must submit a SIP revision to comply with the requirements of section 110(a)(2)(D)(i)(I), 42 U.S.C. 7410(a)(2)(D)(i)(I), through the adoption of adequate provisions prohibiting sources and other activities from emitting NO_X in amounts that will contribute significantly to nonattainment in, or interfere with maintenance by, one or more other States with respect to the 8-hour ozone NAAQS.

(b)(1) For each jurisdiction listed in paragraph (c) of this section, the SIP revision required under paragraph (a) of this section will contain adequate provisions, for purposes of complying with section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), only if the SIP revision:

(i) Contains control measures adequate to prohibit emissions of NO_X that would otherwise be projected, in accordance with paragraph (g) of this section, to cause the jurisdiction's overall NO_X emissions to be in excess of the budget for that jurisdiction described in paragraph (e) of this section (except as provided in paragraph (b)(2) of this section),

(ii) Requires full implementation of all such control measures by no later than May 1, 2003, and

(iii) Meets the other requirements of this section. The SIP revision's compliance with the requirement of paragraph (b)(1)(i) of this section shall be considered compliance with the jurisdiction's budget for purposes of this section.

(2) The requirements of paragraph (b)(1)(i) of this section shall be deemed satisfied, for the portion of the budget covered by an interstate trading program, if the SIP revision:

(i) Contains provisions for an interstate trading program that EPA determines will, in conjunction with interstate trading programs for one or more other jurisdictions, prohibit NO_X emissions in excess of the sum of the portion of the budgets covered by the trading programs for those jurisdictions; and

(ii) Conforms to the following criteria:

(A) Emissions reductions used to demonstrate compliance with the revision must occur during the ozone season.

(B) Emissions reductions occurring prior to the year 2003 may be used by a source to demonstrate compliance with the SIP revision for the 2003 and 2004 ozone seasons, provided the SIP's provisions regarding such use comply with the requirements of paragraph (e)(3) of this section.

(C) Emissions reduction credits or emissions allowances held by a source or other person following the 2003 ozone season or any ozone season thereafter that are not required to demonstrate compliance with the SIP for the relevant ozone season may be banked and used to demonstrate compliance with the SIP in a subsequent ozone season.

(D) Early reductions created according to the provisions in paragraph (b)(2)(ii)(B) of this section and used in the 2003 ozone season are not subject to the flow control provisions set forth in paragraph (b)(2)(ii)(E) of this section.

(E) Starting with the 2004 ozone season, the SIP shall include provisions to limit the use of banked emissions reduction credits or emissions allowances beyond a predetermined amount as calculated by one of the following approaches:

(*1*) Following the determination of compliance after each ozone season, if the total number of emissions reduction credits or banked allowances held by sources or other persons subject to the trading program exceeds 10 percent of the sum of the allowable ozone season NO_X emissions for all sources subject to the trading program, then all banked allowances used for compliance for the following ozone season shall be subject to the following:

(*i*) A ratio will be established according to the following formula: $(0.10) \times$ (the sum of the allowable ozone season NO_X emissions for all sources subject to the trading program) $\div$ (the total number of banked emissions reduction credits or emissions allowances held by all sources or other persons subject to the trading program).

(*ii*) The ratio, determined using the formula specified in paragraph (b)(2)(ii)(E)(1)(i) of this section, will be multiplied by the number of banked emissions reduction credits or emissions allowances held in each account at the time of compliance determination. The resulting product is the number of banked emissions reduction credits or emissions allowances in the account which can be used in the current year's ozone season at a rate of 1 credit or allowance for every 1 ton of emissions. The SIP shall specify that banked emissions reduction credits or emissions allowances in excess of the resulting product either may not be used for compliance, or may only be used for compliance at a rate no less than 2 credits or allowances for every 1 ton of emissions.

(*2*) At the time of compliance determination for each ozone season, if the total number of banked emissions reduction credits or emissions allowances held by a source subject to the trading program exceeds 10 percent of the source's allowable ozone season NO_X emissions, all banked emissions reduction credits or emissions allowances used for compliance in such ozone season by the source shall be subject to the following:

(*i*) The source may use an amount of banked emissions reduction credits or emissions allowances not greater than 10 percent of the source's allowable ozone season NO_X emissions for compliance at a rate of 1 credit or allowance for every 1 ton of emissions.

(*ii*) The SIP shall specify that banked emissions reduction credits or emissions allowances in excess of 10 percent of the source's allowable ozone season NO_X emissions may not be used for compliance, or may only be used for compliance at a rate no less than 2 credits or allowances for every 1 ton of emissions.

(c) The following jurisdictions (hereinafter referred to as "States") are subject to the requirements of this section: Alabama, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin, and the District of Columbia.

(d)(1) The SIP submissions required under paragraph (a) of this section must be submitted to EPA by no later than September 30, 1999.

(2) The State makes an official submission of its SIP revision to EPA only when:

(i) The submission conforms to the requirements of appendix V to this part; and

(ii) The State delivers five copies of the plan to the appropriate Regional Office, with a letter giving notice of such action.

(e)(1) The NO_X budget for a State listed in paragraph (c) of this section is defined as the total amount of NO_X emissions from all sources in that State, as indicated in paragraph (e)(2) of this section with respect to that State, which the State must demonstrate that it will not exceed in the 2007 ozone season pursuant to paragraph (g)(1) of this section.

(2) The State-by-State amounts of the NO_X budget, expressed in tons, are as follows:

State	Budget
Alabama	158,677
Connecticut	40,573
Delaware	18,523
District of Columbia	6,792
Georgia	177,381
Illinois	210,210
Indiana	202,584
Kentucky	155,698
Maryland	71,388
Massachusetts	78,168
Michigan	212,199
Missouri	114,532
New Jersey	97,034
New York	179,769
North Carolina	151,847
Ohio	239,898
Pennsylvania	252,447
Rhode Island	8,313
South Carolina	109,425
Tennessee	182,476
Virginia	155,718
West Virginia	92,920
Wisconsin	106,540
Total	3,023,113

(3)(i) Notwithstanding the State's obligation to comply with the budgets set forth in paragraph (e)(2) of this section, a SIP revision may allow sources required by the revision to implement NO_X emission control measures by May 1, 2003 to demonstrate compliance in the 2003 and 2004 ozone seasons using credit issued from the State's compliance supplement pool, as set forth in paragraph (e)(3)(iii) of this section.

(ii) A source may not use credit from the compliance supplement pool to demonstrate compliance after the 2004 ozone season.

(iii) The State-by-State amounts of the compliance supplement pool are as follows:

State	Compliance supplement pool (tons of NO_X)
Alabama	10,361
Connecticut	559
Delaware	417
District of Columbia	0
Georgia	10,919
Illinois	17,455
Indiana	19,738
Kentucky	13,018
Maryland	3,662
Massachusetts	285
Michigan	15,359
Missouri	10,469
New Jersey	1,722
New York	1,831
North Carolina	10,624
Ohio	22,947
Pennsylvania	13,716
Rhode Island	0
South Carolina	5,062
Tennessee	12,093
Virginia	6,108
West Virginia	16,937
Wisconsin	6,717
Total	200,000

(iv) The SIP revision may provide for the distribution of the compliance supplement pool to sources that are required to implement control measures using one or both of the following two mechanisms:

(A) The State may issue some or all of the compliance supplement pool to sources that implement emissions reductions during the ozone season beyond all applicable requirements in years prior to the year 2003 according to the following provisions:

(1) The State shall complete the issuance process by no later than May 1, 2003.

(2) The emissions reduction may not be required by the State's SIP or be otherwise required by the CAA.

(*3*) The emissions reduction must be verified by the source as actually having occurred during an ozone season between September 30, 1999 and May 1, 2003.

(*4*) The emissions reduction must be quantified according to procedures set forth in the SIP revision and approved by EPA. Emissions reductions implemented by sources serving electric generators with a nameplate capacity greater than 25 MWe, or boilers, combustion turbines or combined cycle units with a maximum design heat input greater than 250 mmBtu/hr, must be quantified according to the requirements in paragraph (i)(4) of this section.

(*5*) If the SIP revision contains approved provisions for an emissions trading program, sources that receive credit according to the requirements of this paragraph may trade the credit to other sources or persons according to the provisions in the trading program.

(B) The State may issue some or all of the compliance supplement pool to sources that demonstrate a need for an extension of the May 1, 2003 compliance deadline according to the following provisions:

(*1*) The State shall initiate the issuance process by the later date of September 30, 2002 or after the State issues credit according to the procedures in paragraph (e)(3)(iv)(A) of this section.

(*2*) The State shall complete the issuance process by no later than May 1, 2003.

(*3*) The State shall issue credit to a source only if the source demonstrates the following:

(*i*) For a source used to generate electricity, compliance with the SIP revision's applicable control measures by May 1, 2003, would create undue risk for the reliability of the electricity supply. This demonstration must include a showing that it would not be feasible to import electricity from other electricity generation systems during the installation of control technologies necessary to comply with the SIP revision.

(*ii*) For a source not used to generate electricity, compliance with the SIP revision's applicable control measures by May 1, 2003, would create undue risk for the source or its associated industry to a degree that is comparable to the risk described in paragraph (e)(3)(iv)(B)(3)(i) of this section.

(*iii*) For a source subject to an approved SIP revision that allows for early reduction credits in accordance with paragraph (e)(3)(iv)(A) of this section, it was not possible for the source to comply with applicable control measures by generating early reduction credits or acquiring early reduction credits from other sources.

(*iv*) For a source subject to an approved emissions trading program, it was not possible to comply with applicable control measures by acquiring sufficient credit from other sources or persons subject to the emissions trading program.

(*4*) The State shall ensure the public an opportunity, through a public hearing process, to comment on the appropriateness of allocating compliance supplement pool credits to a source under paragraph (e)(3)(iv)(B) of this section.

(4) If, no later than November 23, 1998, any member of the public requests revisions to the source-specific data used to establish the State budgets set forth in paragraph (e)(2) of this section or the 2007 baseline sub-inventory information set forth in paragraph (g)(2)(ii) of this section, then EPA will act on that request no later than January 22, 1999, provided:

(i) The request is submitted in electronic format;

(ii) Information is provided to corroborate and justify the need for the requested modification;

(iii) The request includes the following data information regarding any electricity-generating source at issue:

(A) Federal Information Placement System (FIPS) State Code;

(B) FIPS County Code;

(C) Plant name;

(D) Plant ID numbers (ORIS code preferred, State agency tracking number also or otherwise);

(E) Unit ID numbers (a unit is a boiler or other combustion device);

(F) Unit type;

(G) Primary fuel on a heat input basis;

(H) Maximum rated heat input capacity of unit;

(I) Nameplate capacity of the largest generator the unit serves;

(J) Ozone season heat inputs for the years 1995 and 1996;

(K) 1996 (or most recent) average NO_X rate for the ozone season;

(L) Latitude and longitude coordinates;

(M) Stack parameter information ;

(N) Operating parameter information;

(o) Identification of specific change to the inventory; and

(p) Reason for the change;

(iv) The request includes the following data information regarding any non-electricity generating point source at issue:

(A) FIPS State Code;

(B) FIPS County Code;

(C) Plant name;

(D) Facility primary standard industrial classification code (SIC);

(E) Plant ID numbers (NEDS, AIRS/AFS, and State agency tracking number also or otherwise);

(F) Unit ID numbers (a unit is a boiler or other combustion device);

(G) Primary source classification code (SCC);

(H) Maximum rated heat input capacity of unit;

(I) 1995 ozone season or typical ozone season daily NO_X emissions;

(J) 1995 existing NO_X control efficiency;

(K) Latitude and longitude coordinates;

(L) Stack parameter information;

(M) Operating parameter information;

(N) Identification of specific change to the inventory; and

(O) Reason for the change;

(v) The request includes the following data information regarding any stationary area source or nonroad mobile source at issue:

(A) FIPS State Code;

(B) FIPS County Code;

(C) Primary source classification code (SCC);

(D) 1995 ozone season or typical ozone season daily NO_X emissions;

(E) 1995 existing NO_X control efficiency;

(F) Identification of specific change to the inventory; and

(G) Reason for the change;

(vi) The request includes the following data information regarding any highway mobile source at issue:

(A) FIPS State Code;

(B) FIPS County Code;

(C) Primary source classification code (SCC) or vehicle type;

(D) 1995 ozone season or typical ozone season daily vehicle miles traveled (VMT);

(E) 1995 existing NO_X control programs;

(F) identification of specific change to the inventory; and

(G) reason for the change.

(f) Each SIP revision must set forth control measures to meet the NO_X budget in accordance with paragraph (b)(1)(i) of this section, which include the following:

(1) A description of enforcement methods including, but not limited to:

(i) Procedures for monitoring compliance with each of the selected control measures;

(ii) Procedures for handling violations; and

(iii) A designation of agency responsibility for enforcement of implementation.

(2) Should a State elect to impose control measures on fossil fuel-fired NO_X sources serving electric generators with a nameplate capacity greater than 25 MWe or boilers, combustion turbines or combined cycle units with a maximum design heat input greater than 250 mmBtu/hr as a means of meeting its NO_X budget, then those measures must:

(i)(A) Impose a NO_X mass emissions cap on each source;

(B) Impose a NO_X emissions rate limit on each source and assume maximum operating capacity for every such source for purposes of estimating mass NO_X emissions; or

(C) Impose any other regulatory requirement which the State has demonstrated to EPA provides equivalent or greater assurance than options in paragraphs (f)(2)(i)(A) or (f)(2)(i)(B) of this section that the State will comply with its NO_X budget in the 2007 ozone season; and

(ii) Impose enforceable mechanisms to assure that collectively all such sources, including new or modified units, will not exceed in the 2007 ozone season the total NO_X emissions projected for such sources by the State pursuant to paragraph (g) of this section.

(3) For purposes of paragraph (f)(2) of this section, the term ''fossil fuel-fired'' means, with regard to a NO_X source:

(i) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel actually combusted comprises more than 50 percent of the annual heat input on a Btu basis during any year starting in 1995 or, if a NO_X source had no heat input starting in 1995, during the last year of operation of the NO_X source prior to 1995; or

(ii) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel is projected to comprise more than 50 percent of the annual heat input on a Btu basis during any year; provided that the NO_X source shall be ''fossil fuel-fired'' as of the date, during such year, on which the NO_X source begins combusting fossil fuel.

(g)(1) Each SIP revision must demonstrate that the control measures contained in it are adequate to provide for the timely compliance with the State's NO_X budget during the 2007 ozone season.

(2) The demonstration must include the following:

(i) Each revision must contain a detailed baseline inventory of NO_X mass emissions from the following sources in the year 2007, absent the control measures specified in the SIP submission: electric generating units (EGU), non-electric generating units (non-EGU), area, nonroad and highway sources. The State must use the same baseline emissions inventory that EPA used in calculating the State's NO_X budget, as set forth for the State in paragraph (g)(2)(ii) of this section, except that EPA may direct the State to use different baseline inventory information if the State fails to certify that it has implemented all of the control measures assumed in developing the baseline inventory.

(ii) The base year 2007 NO_X emissions sub-inventories for each State, expressed in tons per ozone season, are as follows:

State	EGU	Non-EGU	Area	Nonroad	Highway	Total
Alabama	76,900	49,781	25,225	16,594	50,111	218,610
Connecticut	5,600	5,273	4,588	9,584	18,762	43,807
Delaware	5,800	1,781	963	4,261	8,131	20,936
District of Columbia	[1] 0	310	741	3,470	2,082	6,603
Georgia	86,500	33,939	11,902	21,588	86,611	240,540
Illinois	119,300	55,721	7,822	47,035	81,297	311,174
Indiana	136,800	71,270	25,544	22,445	60,694	316,753
Kentucky	107,800	18,956	38,773	19,627	45,841	230,997
Maryland	32,600	10,982	4,105	17,249	27,634	92,570
Massachusetts	16,500	9,943	10,090	18,911	24,371]	79,815
Michigan	86,600	79,034	28,128	23,495	83,784	301,042
Missouri	82,100	13,433	6,603	17,723	55,230	175,089
New Jersey	18,400	22,228	11,098	21,163	34,106	106,995
New York	39,200	25,791	15,587	29,260	80,521	190,358
North Carolina	84,800	34,027	10,651	17,799	66,019	213,296
Ohio	163,100	53,241	19,425	37,781	99,079	372,626
Pennsylvania	123,100	73,748	17,103	25,554	92,280	331,785

State	EGU	Non-EGU	Area	Nonroad	Highway	Total
Rhode Island	1,100	327	420	2,073	4,375	8,295
South Carolina	36,300	34,740	8,359	11,903	47,404	138,706
Tennessee	70,900	60,004	11,990	44,567	64,965	252,426
Virginia	40,900	39,765	18,622	21,551	70,212	191,050
West Virginia	115,500	40,192	4,790	10,220	20,185	190,887
Wisconsin	52,000	22,796	8,160	12,965	49,470	145,391
Total	1,501,800	757,281	290,689	456,818	1,173,163	4,179,751

[1] The base case for the District of Columbia is actually projected to be 30 tons per season. The base case values in this table are rounded to the nearest 100 tons.

(iii) Each revision must contain a summary of NO_X mass emissions in 2007 projected to result from implementation of each of the control measures specified in the SIP submission and from all NO_X sources together following implementation of all such control measures, compared to the baseline 2007 NO_X emissions inventory for the State described in paragraph (g)(2)(i) of this section. The State must provide EPA with a summary of the computations, assumptions, and judgments used to determine the degree of reduction in projected 2007 NO_X emissions that will be achieved from the implementation of the new control measures compared to the baseline emissions inventory.

(iv) Each revision must identify the sources of the data used in the projection of emissions.

(h) Each revision must comply with § 51.116 of this part (regarding data availability).

(i) Each revision must provide for monitoring the status of compliance with any control measures adopted to meet the NO_X budget. Specifically, the revision must meet the following requirements:

(1) The revision must provide for legally enforceable procedures for requiring owners or operators of stationary sources to maintain records of and periodically report to the State:

(i) Information on the amount of NO_X emissions from the stationary sources; and

(ii) Other information as may be necessary to enable the State to determine whether the sources are in compliance with applicable portions of the control measures;

(2) The revision must comply with § 51.212 of this part (regarding testing, inspection, enforcement, and complaints);

(3) If the revision contains any transportation control measures, then the revision must comply with § 51.213 of this part (regarding transportation control measures);

(4) If the revision contains measures to control fossil fuel-fired NO_X sources serving electric generators with a nameplate capacity greater than 25 MWe or boilers, combustion turbines or combined cycle units with a maximum design heat input greater than 250 mmBtu/hr, then the revision must require such sources to comply with the monitoring provisions of part 75, subpart H.

(5) For purposes of paragraph (i)(4) of this section, the term ''fossil fuel-fired'' means, with regard to a NO_X source:

(i) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel actually combusted comprises more than 50 percent of the annual heat input on a Btu basis during any year starting in 1995 or, if a NO_X source had no heat input starting in 1995, during the last year of operation of the NO_X source prior to 1995; or

(ii) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel is projected to comprise more than 50 percent of the annual heat input on a Btu basis during any year, provided that the NO_X source shall be ''fossil fuel-fired'' as of the date, during such year, on which the NO_X source begins combusting fossil fuel.

(j) Each revision must show that the State has legal authority to carry out the revision, including authority to:

(1) Adopt emissions standards and limitations and any other measures necessary for attainment and maintenance of the State's NO_X budget specified in paragraph (e) of this section;

(2) Enforce applicable laws, regulations, and standards, and seek injunctive relief;

(3) Obtain information necessary to determine whether air pollution sources are in compliance with applicable laws, regulations, and standards, including authority to require recordkeeping and to make inspections and conduct tests of air pollution sources;

(4) Require owners or operators of stationary sources to install, maintain, and use emissions monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such stationary sources; also authority for the State to make such data available to the public as reported and as correlated with any applicable emissions standards or limitations.

(k)(1) The provisions of law or regulation which the State determines provide the authorities required under this section must be specifically identified, and copies of such laws or regulations must be submitted with the SIP revision.

(2) Legal authority adequate to fulfill the requirements of paragraphs (j)(3) and (4) of this section may be delegated to the State under section 114 of the CAA.

(l)(1) A revision may assign legal authority to local agencies in accordance with § 51.232 of this part.

(2) Each revision must comply with § 51.240 of this part (regarding general plan requirements).

(m) Each revision must comply with § 51.280 of this part (regarding resources).

(n) For purposes of the SIP revisions required by this section, EPA may make a finding as applicable under section 179(a)(1)–(4) of the CAA, 42 U.S.C. 7509(a)(1)–(4), starting the sanctions process set forth in section 179(a) of the CAA. Any such finding will be deemed a finding under § 52.31(c) of this part and sanctions will be imposed in accordance with the order of sanctions and the terms for such sanctions established in § 52.31 of this part.

(o) Each revision must provide for State compliance with the reporting requirements set forth in § 51.122 of this part.

(p)(1) Notwithstanding any other provision of this section, if a State adopts regulations substantively identical to 40 CFR part 96 (the model NO_X budget trading program for SIPs), incorporates such part by reference into its regulations, or adopts regulations that differ substantively from such part only as set forth in paragraph (p)(2) of this section, then that portion of the State's SIP revision is automatically approved as satisfying the same portion of the State's NO_X emission reduction obligations as the State projects such regulations will satisfy, provided that:

(i) The State has the legal authority to take such action and to implement its responsibilities under such regulations, and

(ii) The SIP revision accurately reflects the NO_X emissions reductions to be expected from the State's implementation of such regulations.

(2) If a State adopts an emissions trading program that differs substantively from 40 CFR part 96 in only the following respects, then such portion of the State's SIP revision is approved as set forth in paragraph (p)(1) of this section:

(i) The State may expand the applicability provisions of the trading program to include units (as defined in 40 CFR 96.2) that are smaller than the size criteria thresholds set forth in 40 CFR 96.4(a);

(ii) The State may decline to adopt the exemption provisions set forth in 40 CFR 96.4(b);

(iii) The State may decline to adopt the opt-in provisions set forth in subpart I of 40 CFR part 96;

(iv) The State may decline to adopt the allocation provisions set forth in subpart E of 40 CFR part 96 and may instead adopt any methodology for allocating NO_X allowances to individual sources, provided that:

(A) The State's methodology does not allow the State to allocate NO_X allowances in excess of the total amount of NO_X emissions which the State has assigned to its trading program; and

(B) The State's methodology conforms with the timing requirements for submission of allocations to the Administrator set forth in 40 CFR 96.41; and

(v) The State may decline to adopt the early reduction credit provisions set forth in 40 CFR 96.55(c) and may instead adopt any methodology for issuing credit from the State's compliance supplement pool that complies with paragraph (e)(3) of this section.

(3) If a State adopts an emissions trading program that differs substantively from 40 CFR part 96 other than as set forth in paragraph (p)(2) of this section, then such portion of the State's SIP revision is not automatically approved as set forth in paragraph (p)(1) of this section but will be reviewed by the Administrator for approvability in accordance with the other provisions of this section.

§ 51.122 Emissions reporting requirements for SIP revisions relating to budgets for NO_X emissions

(a) For its transport SIP revision under § 51.121 of this part, each State must submit to EPA NO_X emissions data as described in this section.

(b) Each revision must provide for periodic reporting by the State of NO_X emissions data to demonstrate whether the State's emissions are consistent with the projections contained in its approved SIP submission.

(1) *Annual reporting.* Each revision must provide for annual reporting of NO_X emissions data as follows:

(i) The State must report to EPA emissions data from all NO_X sources within the State for which the State specified control measures in its SIP submission under § 51.121(g) of this part. This would include all sources for which the State has adopted measures that differ from the measures incorporated into the baseline inventory for the year 2007 that the State developed in accordance with § 51.121(g) of this part.

(ii) If sources report NO_X emissions data to EPA annually pursuant to a trading program approved under § 51.121(p) of this part or pursuant to the monitoring and reporting requirements of subpart H of 40 CFR part 75, then the State need not provide annual reporting to EPA for such sources.

(2) *Triennial reporting.* Each plan must provide for triennial (i.e., every third year) reporting of NO_X emissions data from all sources within the State.

(3) *Year 2007 reporting.* Each plan must provide for reporting of year 2007 NO_X emissions data from all sources within the State.

(4) The data availability requirements in § 51.116 of this part must be followed for all data submitted to meet the requirements of paragraphs (b)(1),(2) and (3) of this section.

(c) The data reported in paragraph (b) of this section for stationary point sources must meet the following minimum criteria:

(1) For annual data reporting purposes the data must include the following minimum elements:

(i) Inventory year.

(ii) State Federal Information Placement System code.

(iii) County Federal Information Placement System code.

(iv) Federal ID code (plant).

(v) Federal ID code (point).

(vi) Federal ID code (process).

(vii) Federal ID code (stack).

(vii) Site name.

(viii) Physical address.

(ix) SCC.

(x) Pollutant code.

(xi) Ozone season emissions.

(xii) Area designation.

(2) In addition, the annual data must include the following minimum elements as applicable to the emissions estimation methodology.

(i) Fuel heat content (annual).

(ii) Fuel heat content (seasonal).

(iii) Source of fuel heat content data.

(iv) Activity throughput (annual).

(v) Activity throughput (seasonal).

(vi) Source of activity/throughput data.

(vii) Spring throughput (%).

(viii) Summer throughput (%).

(ix) Fall throughput (%).

(x) Work weekday emissions.

(xi) Emission factor.

(xii) Source of emission factor.

(xiii) Hour/day in operation.

(xiv) Operations Start time (hour).

(xv) Day/week in operation.

(xvi) Week/year in operation.

(3) The triennial and 2007 inventories must include the following data elements:

(i) The data required in paragraphs (c)(1) and (c)(2) of this section.

(ii) X coordinate (latitude).

(iii) Y coordinate (longitude).

(iv) Stack height.

(v) Stack diameter.

(vi) Exit gas temperature.

(vii) Exit gas velocity.

(viii) Exit gas flow rate.

(ix) SIC.

(x) Boiler/process throughput design capacity.

(xi) Maximum design rate.

(xii) Maximum capacity.

(xiii) Primary control efficiency.

(xiv) Secondary control efficiency.

(xv) Control device type.

(d) The data reported in paragraph (b) of this section for area sources must include the following minimum elements:

(1) For annual inventories it must include:

(i) Inventory year.

(ii) State FIPS code.

(iii) County FIPS code.

(iv) SCC.

(v) Emission factor.

(vi) Source of emission factor.

(vii) Activity/throughput level (annual).

(viii) Activity throughput level (seasonal).

(ix) Source of activity/throughput data.

(x) Spring throughput (%).

(xi) Summer throughput (%).

(xii) Fall throughput (%).

(xiii) Control efficiency (%).

(xiv) Pollutant code.

(xv) Ozone season emissions.

(xvi) Source of emissions data.

(xvii) Hour/day in operation.

(xviii) Day/week in operation.

(xix) Week/year in operations.

(2) The triennial and 2007 inventories must contain, at a minimum, all the data required in paragraph (d)(1) of this section.

(e) The data reported in paragraph (b) of this section for mobile sources must meet the following minimum criteria:

(1) For the annual, triennial, and 2007 inventory purposes, the following data must be reported:

(i) Inventory year.

(ii) State FIPS code.

(iii) County FIPS code.

(iv) SCC.

(v) Emission factor.

(vi) Source of emission factor.

(vii) Activity (this must be reported for both highway and nonroad activity. Submit nonroad activity in the form of hours of activity at standard load (either full load or average load) for each engine type, application, and horsepower range. Submit highway activity in the form of vehicle miles traveled (VMT) by vehicle class on each roadway type. Report both highway and nonroad activity for a typical ozone season weekday day, if the State uses EPA's default weekday/weekend activity ratio. If the State uses a different weekday/weekend activity ratio, submit separate activity level information for weekday days and weekend days).

(viii) Source of activity data.

(ix) Pollutant code.

(x) Summer work weekday emissions.

(xi) Ozone season emissions.

(xii) Source of emissions data.

(2) [Reserved]

(f) *Approval of ozone season calculation by EPA.* Each State must submit for EPA approval an example of the calculation procedure used to calculate ozone season emissions along with sufficient information for EPA to verify the calculated value of ozone season emissions.

(g) *Reporting schedules.* (1) Annual reports are to begin with data for emissions occurring in the year 2003.

(2) Triennial reports are to begin with data for emissions occurring in the year 2002.

(3) Year 2007 data are to be submitted for emissions occurring in the year 2007.

(4) States must submit data for a required year no later than 12 months after the end of the calendar year for which the data are collected.

(h) *Data reporting procedures.* When submitting a formal NO_X budget emissions report and associated data, States shall notify the appropriate EPA Regional Office.

(1) States are required to report emissions data in an electronic format to one of the locations listed in this paragraph (h). Several options are available for data reporting.

(2) An agency may choose to continue reporting to the EPA Aerometric Information Retrieval System (AIRS) system using the AIRS facility subsystem (AFS) format for point sources. (This option will continue for point sources for some period of time after AIRS is reengineered (before 2002), at which time this choice may be discontinued or modified.)

(3) An agency may convert its emissions data into the Emission Inventory Improvement Program/Electronic Data Interchange (EIIP/EDI) format. This file can then be made available to any requestor, either using E-mail, floppy disk, or value added network (VAN), or can be placed on a file transfer protocol (FTP) site.

(4) An agency may submit its emissions data in a proprietary format based on the EIIP data model.

(5) For options in paragraphs (h)(3) and (4) of this section, the terms submitting and reporting data are defined as either providing the data in the EIIP/EDI format or the EIIP based data model proprietary format to EPA, Office of Air Quality Planning and Standards, Emission Factors and Inventory Group, directly or notifying this group that the data are available in the specified format and at a specific electronic location (e.g., FTP site).

(6) For annual reporting (not for triennial reports), a State may have sources submit the data directly to EPA to the extent the sources are subject to a trading program that qualifies for approval under § 51.121(q) of this part, and the State has agreed to accept data in this format. The EPA will make both the raw data submitted in this format and summary data available to any State that chooses this option.

(i) *Definitions.* As used in this section, the following words and terms shall have the meanings set forth below:

(1) *Annual emissions.* Actual emissions for a plant, point, or process, either measured or calculated.

(2) *Ash content.* Inert residual portion of a fuel.

(3) *Area designation.* The designation of the area in which the reporting source is located with regard to the ozone NAAQS. This would include attainment or nonattainment designations. For nonattainment designations, the classification of the nonattainment area must be specified, i.e., transitional, marginal, moderate, serious, severe, or extreme.

(4) *Boiler design capacity.* A measure of the size of a boiler, based on the reported maximum continuous steam flow. Capacity is calculated in units of MMBtu/hr.

(5) *Control device type.* The name of the type of control device (e.g., wet scrubber, flaring, or process change).

(6) *Control efficiency.* The emissions reduction efficiency of a primary control device, which shows the amount of reductions of a particular pollutant from a process' emissions due to controls or material change. Control efficiency is usually expressed as a percentage or in tenths.

(7) *Day/week in operations.* Days per week that the emitting process operates.

(8) *Emission factor.* Ratio relating emissions of a specific pollutant to an activity or material throughput level.

(9) *Exit gas flow rate.* Numeric value of stack gas flow rate.

(10) *Exit gas temperature.* Numeric value of an exit gas stream temperature.

(11) *Exit gas velocity.* Numeric value of an exit gas stream velocity.

(12) *Fall throughput (%).* Portion of throughput for the 3 fall months (September, October, November). This represents the expression of annual activity information on the basis of four seasons, typically spring, summer, fall, and winter. It can be represented either as a percentage of the annual activity (e.g., production in summer is 40 percent of the year's production), or in terms of the units of the activity (e.g., out of 600 units produced, spring = 150 units, summer = 250 units, fall = 150 units, and winter = 50 units).

(13) *Federal ID code (plant).* Unique codes for a plant or facility, containing one or more pollutant-emitting sources.

(14) *Federal ID code (point).* Unique codes for the point of generation of emissions, typically a physical piece of equipment.

(15) *Federal ID code (stack number).* Unique codes for the point where emissions from one or more processes are released into the atmosphere.

(16) *Federal Information Placement System (FIPS).* The system of unique numeric codes developed by the government to identify States, counties, towns, and townships for the entire United States, Puerto Rico, and Guam.

(17) *Heat content.* The thermal heat energy content of a solid, liquid, or gaseous fuel. Fuel heat content is typically expressed in units of Btu/lb of fuel, Btu/gal of fuel, joules/kg of fuel, etc.

(18) *Hr/day in operations.* Hours per day that the emitting process operates.

(19) *Maximum design rate.* Maximum fuel use rate based on the equipment's or process' physical size or operational capabilities.

(20) *Maximum nameplate capacity.* A measure of the size of a generator which is put on the unit's nameplate by the manufacturer. The data element is reported in megawatts (MW) or kilowatts (KW).

(21) *Mobile source.* A motor vehicle, nonroad engine or nonroad vehicle, where:

(i) *Motor vehicle* means any self-propelled vehicle designed for transporting persons or property on a street or highway;

(ii) *Nonroad engine* means an internal combustion engine (including the fuel system) that is not used in a motor vehicle or a vehicle used solely for competition, or that is not subject to standards promulgated under section 111 or section 202 of the CAA;

(iii) *Nonroad vehicle* means a vehicle that is powered by a nonroad engine and that is not a motor vehicle or a vehicle used solely for competition.

(22) *Ozone season.* The period May 1 through September 30 of a year.

(23) *Physical address.* Street address of facility.

(24) *Point source.* A non-mobile source which emits 100 tons of NO_X or more per year unless the State designates as a point source a non-mobile source emitting at a specified level lower than 100 tons of NO_X per year. A non-mobile source which emits less NO_X per year than the point source threshold is an area source.

(25) *Pollutant code.* A unique code for each reported pollutant that has been assigned in the EIIP Data Model. Character names are used for criteria pollutants, while Chemical Abstracts Service (CAS) numbers are used for all other pollutants. Some States may be using storage and retrieval of aerometric data (SAROAD) codes for pollutants, but these should be able to be mapped to the EIIP Data Model pollutant codes.

(26) *Process rate/throughput.* A measurable factor or parameter that is directly or indirectly related to the emissions of an air pollution source. Depending on the type of source category, activity information may refer to the amount of fuel combusted, the amount of a raw material processed, the amount of a product that is manufactured, the amount of a material that is handled or processed, population, employment, number of units, or miles traveled. Activity information is typically the value that is multiplied against an emission factor to generate an emissions estimate.

(27) *SCC. Source category code.* A process-level code that describes the equipment or operation emitting pollutants.

(28) *Secondary control efficiency (%).* The emissions reductions efficiency of a secondary control device, which shows the amount of reductions of a particular pollutant from a process' emissions due to controls or material change. Control efficiency is usually expressed as a percentage or in tenths.

(29) *SIC.* Standard Industrial Classification code. U.S. Department of Commerce's categorization of businesses by their products or services.

(30) *Site name.* The name of the facility.

(31) *Spring throughput (%).* Portion of throughput or activity for the 3 spring months (March, April, May). See the definition of Fall Throughput.

(32) *Stack diameter.* Stack physical diameter.

(33) *Stack height.* Stack physical height above the surrounding terrain.

(34) *Start date (inventory year).* The calendar year that the emissions estimates were calculated for and are applicable to.

(35) *Start time (hour).* Start time (if available) that was applicable and used for calculations of emissions estimates.

(36) *Summer throughput (%).* Portion of throughput or activity for the 3 summer months (June, July, August). See the definition of Fall Throughput.

(37) *Summer work weekday emissions.* Average day's emissions for a typical day.

(38) *VMT by Roadway Class.* This is an expression of vehicle activity that is used with emission factors. The emission factors are usually expressed in terms of grams per mile of travel. Since VMT does not directly correlate to emissions that occur while the vehicle is not moving, these non-moving emissions are incorporated into EPA's MOBILE model emission factors.

(39) *Week/year in operation.* Weeks per year that the emitting process operates.

(40) *Work Weekday.* Any day of the week except Saturday or Sunday.

(41) *X coordinate (latitude).* East-west geographic coordinate of an object.

(42) *Y coordinate (longitude).* North-south geographic coordinate of an object.

PART 72—PERMITS REGULATION

1. The authority for part 72 continues to read as follows:

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

2. Section 72.2 is amended by revising the definition for ''excepted monitoring system,'' and adding new definitions in alphabetical order for ''low mass emissions unit'', ''maximum potential hourly heat input'', ''maximum rated hourly heat input,'' and ''ozone season'' to read as follows:

§ 72.2 Definitions.

* * * * *

Excepted monitoring system means a monitoring system that follows the procedures and requirements of § 75.19 of this chapter or of appendix D or E to part 75 for approved exceptions to the use of continuous emission monitoring systems.

* * * * *

Low mass emissions unit means an affected unit that is a gas-fired or oil-fired unit, burns only natural gas or fuel oil and qualifies under § 75.19 of this chapter.

* * * * *

Maximum potential hourly heat input means an hourly heat input used for reporting purposes when a unit lacks certified monitors to report heat input. If the unit intends to use appendix D of part 75 of this chapter to report heat input, this value should be calculated, in accordance with part 75 of this chapter, using the maximum fuel flow rate and the maximum gross calorific value. If the unit intends to use a flow monitor and a diluent gas monitor, this value should be reported, in accordance with part 75 of this chapter, using the maximum potential flow rate and either the maximum carbon dioxide concentration (in percent CO_2) or the minimum oxygen concentration (in percent O_2).

* * * * *

Maximum rated hourly heat input means a unit-specific maximum hourly heat input (mmBtu) which is the higher of the manufacturer's maximum rated hourly heat input or the highest observed hourly heat input.

* * * * *

Ozone season means the period of time beginning May 1 of a year and ending on September 30 of the same year, inclusive.

* * * * *

PART 75—CONTINUOUS EMISSION MONITORING

3. The authority citation for part 75 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651k, 7651 and note.

4. Section 75.1 is amended by revising paragraph (a) to read as follows:

§ 75.1 Purpose and scope.

(a) *Purpose.* The purpose of this part is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2) emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program pursuant to sections 412 and 821 of the CAA, 42 U.S.C. 7401–7671q as amended by Public Law 101–549 (November 15, 1990). In addition, this part sets forth provisions for the monitoring, recordkeeping, and reporting of NO_X mass emissions with which EPA, individual States, or groups of States may require sources to comply in order to demonstrate compliance with a NO_X mass emission reduction program, to the extent these provisions are adopted as requirements under such a program.

* * * * *

5. Section 75.2 is amended by revising paragraph (a) and adding a new paragraph (c) to read as follows:

§ 75.2 Applicability.

(a) Except as provided in paragraphs (b) and (c) of this section, the provisions of this part apply to each affected unit subject to Acid Rain emission limitations or reduction requirements for SO_2 or NO_X.

* * * * *

(c) The provisions of this part apply to sources subject to a State or federal NO_X mass emission reduction program, to the extent these provisions are adopted as requirements under such a program.

6. Section 75.4 is amended by revising paragraph (a) introductory text to read as follows:

§ 75.4 Compliance dates.

(a) The provisions of this part apply to each existing Phase I and Phase II unit on February 10, 1993. For substitution or compensating units that are so designated under the Acid Rain permit which governs that unit and contains the approved substitution or reduced utilization plan, pursuant to § 72.41 or § 72.43 of this chapter, the provisions of this part become applicable upon the issuance date of the Acid Rain permit. For combustion sources seeking to enter the Opt-in Program in accordance with part 74 of this chapter, the provisions of this part become applicable upon the submission of an opt-in permit application in accordance with § 74.14 of this chapter. The provisions of this part for the monitoring, recording, and reporting of NO_X mass emissions become applicable on the deadlines specified in the applicable State or federal NO_X mass emission reduction program, to the extent these provisions are adopted as requirements under such a program. In accordance with § 75.20, the owner or operator of each existing affected unit shall ensure that all monitoring systems required by this part for monitoring SO_2, NO_X, CO_2, opacity, and volumetric flow are installed and that all certification tests are completed no later than the following dates (except as provided in paragraphs (d) through (h) of this section):

* * * * *

7. Section 75.6 is amended by adding paragraph (f) to read as follows:

§ 75.6 Incorporation by reference.

* * * * *

(f) The following materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street NW, Washington, DC 20005–4070.

(1) American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992 (reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997; for § 75.19.

(2) Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992), for § 75.19.

8. Section 75.11 is amended by removing the period at the end of paragraph (d)(2) and replacing it with ''; or'' and adding paragraph (d)(3), to read as follows:

§ 75.11 Specific provisions for monitoring SO_2 emissions (SO_2 and flow monitors).

* * * * *

(d) * * *

(3) By using the low mass emissions excepted methodology in § 75.19(c) for estimating hourly SO_2 mass emissions if the affected unit qualifies as a low mass emissions unit under § 75.19(a) and (b).

* * * * *

9. Section 75.12 is amended by revising the section heading, by redesignating paragraph (d) as paragraph (e), and by adding new paragraph (d) to read as follows:

§ 75.12 Specific provisions for monitoring NO_X emission rate (NO_X and diluent gas monitors).

* * * * *

(d) *Low mass emissions units.* Notwithstanding the requirements of paragraphs (a) and (c) of this section, the owner or operator of an affected unit that qualifies as a low mass emissions unit under § 75.19(a) and (b) shall comply with one of the following:

(1) Meet the general operating requirements in § 75.10 for a NO_X continuous emission monitoring system;

(2) Meet the requirements specified in paragraph (d)(2) of this section for using the excepted monitoring procedures in appendix E to this part, if applicable; or

(3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly NO_X emission rate and hourly NO_X mass emissions, if applicable under § 75.19(a) and (b).

* * * * *

10. Section 75.13 is amended by adding paragraph (d) to read as follows:

§ 75.13 Specific provisions for monitoring CO_2 emissions.

* * * * *

(d) *Determination of CO_2 mass emissions from low mass emissions units.* The owner or operator of a unit that qualifies as a low mass emissions unit under § 75.19(a) and (b) shall comply with one of the following:

(1) Meet the general operating requirements in § 75.10 for a CO_2 continuous emission monitoring system and flow monitoring system;

(2) Meet the requirements specified in paragraph (b) or (c) of this section for use of the methods in appendix G or F to this part, respectively; or

(3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly CO_2 mass emissions, if applicable under § 75.19(a) and (b).

* * * * *

11. Section 75.17 is amended by adding introductory text before paragraph (a) to read as follows:

§ 75.17 Specific provisions for monitoring emissions from common, by-pass, and multiple stacks for NO_X emission rate.

Notwithstanding the provisions of paragraphs (a), (b), and (c) of this section, the owner or operator of an affected unit that is using the procedures in this part to meet the monitoring and reporting requirements of a State or federal NO_X mass emission reduction program must also meet the provisions for monitoring NO_X emission rate in §§ 75.71 and 75.72.

* * * * *

12. Section 75.19 is added to subpart B to read as follows:

§ 75.19 Optional SO_2, NO_X, and CO_2 emissions calculation for low mass emissions units.

(a) *Applicability.* (1) Consistent with the requirements of paragraphs (a)(2) and (b) of this section, the low mass emissions excepted methodology in paragraph (c) of this section may be used in lieu of continuous emission monitoring systems or, if applicable, in lieu of excepted methods under appendix D or E to this part, for the purpose of determining hourly heat input and hourly NO_X, SO_2, and CO_2 mass emissions from a low mass emissions unit.

(i) A low mass emissions unit is an affected unit that is gas-fired, or oil-fired unit, that burns only natural gas or fuel oil and for which:

(A) An initial demonstration is provided, in accordance with paragraph (a)(2) of this section, which shows that the unit emits no more than 25 tons of SO_2 annually and no more than 50 tons of NO_X annually; and

(B) An annual demonstration is provided thereafter, using one of the allowable methodologies in paragraph (c) of this section, showing that the low mass emission unit continues to emit no more than 25 tons of SO_2 annually and no more than 50 tons of NO_X annually.

(ii) Any qualifying unit must start using the low mass emissions excepted methodology in the first hour in which the unit operates in a calendar year. Notwithstanding, the earliest date for which a unit that meets the eligibility requirements of this section may begin to use this methodology is January 1, 2000.

(2) A unit may initially qualify as a low mass emissions unit only under the following circumstances:

(i) If the designated representative submits a certification application to use the low mass emissions excepted methodology and the Administrator certifies the use of such methodology. The certification application must contain:

(A) Actual SO_2 and NO_X mass emissions data for each of the three calendar years prior to the calendar year in which the certification application is submitted demonstrating to the satisfaction of the Administrator that the unit emits less than 25 tons of SO_2 and less than 50 tons of NO_X annually; and

(B) Calculated SO_2 and NO_X mass emissions, for each of the three calendar years prior to the calendar year in which the certification application is submitted, demonstrating to the satisfaction of the Administrator that the unit emits less than 25 tons of SO_2 and less than 50 tons of NO_X annually. The calculated emissions for each year shall be determined using either the maximum rated heat input methodology described in paragraph (c)(3)(i) of this section or the long term fuel flow heat input methodology described in paragraph (c)(3)(ii) of this section, in conjunction with the appropriate SO_2, NO_X, and CO_2 emission rate from paragraph (c)(1)(i) of this section for SO_2, paragraph (c)(1)(ii) or (c)(1)(iv) of this section for NO_X and paragraph (c)(1)(iii) of this section for CO_2; or

(ii) When the three full years of actual, historical SO_2 and NO_X mass emissions data required under paragraph (a)(2)(i) of this section are not available, the designated representative may submit an application to use the low mass emissions excepted methodology based upon a combination of historical SO_2 and NO_X mass emissions data and projected SO_2 and NO_X mass emissions, totaling three years. Historical data must be used for any years in which historical data exists and projected data should be used for any remaining future years needed to provide capacity factor data for three consecutive calender years. For example, if a unit commenced operation two years ago, the designated representative may submit actual, historical data for the previous two years and one year of projected emissions for the current calendar year or, for unit that commenced operation after January 1, 1997, the designated representative may submit three years of projected emissions, beginning with the current calendar year. Any actual or projected annual emissions must demonstrate to the satisfaction of the Administrator that the unit will emit less than 25 tons of SO_2 and less than 50 tons of NO_X annually. Projected emissions shall be calculated using either the default emission rates in tables 1,2 and 3 of this section, or for NO_X emission rate a fuel-and-unit-specific NO_X emission rate determined in accordance with the testing procedures in paragraph (c)(1)(iv) of this section, in conjunction with projections of unit operating hours or fuel type and fuel usage, according to one of the allowable calculation methodologies in paragraph (c) of this section.

(b) *On-going qualification and disqualification.* (1) Once a low mass emission unit has qualified for and has started using the low mass emissions excepted methodology, an annual demonstration is required, showing that the unit continues to emit less than 25 tons of SO_2 annually and less than 50 tons of NO_X annually. The calculation methodology used for the annual demonstration shall be the same methodology, from paragraph (c) of this section, by which the unit initially qualified to use the low mass emissions excepted methodology.

(2) If any low mass emission unit fails to provide the required annual demonstration under paragraph (b)(1) of this section, such that the calculated cumulative year-to-date emissions for the unit exceed 25 tons of SO_2 or 50 tons of NO_X in any calendar quarter of any calendar year, then;

(i) The low mass emission unit shall be disqualified from using the low mass emissions excepted methodology as of the end of the second calendar quarter following such quarter in which either the 25 ton limit for SO_2 or the 50 ton limit for NO_X was exceeded; and

(ii) The owner or operator of the low mass emission unit shall have two calendar quarters from the end of the quarter in which the unit exceeded the 25 ton limit for SO_2 or the 50 ton limit for NO_X to install, certify, and report SO_2, NO_X, and CO_2 emissions from monitoring systems that meet the requirements of §§ 75.11, 75.12, and 75.13.

(3) If a low mass emission unit that initially qualifies to use the low mass emissions excepted methodology under this section changes fuels, such that a fuel other than those allowed for use in the low mass emissions methodology (e.g. natural gas or fuel oil) is combusted in the unit, the unit shall be disqualified from using the low mass emissions excepted methodology as of the first hour that the new fuel is combusted in the unit. The owner or operator shall install, certify, and report SO_2, NO_X, and CO_2 from monitoring systems that meet the requirements of §§ 75.11, 75.12, and 75.13 prior to a change to such fuel. The owner or operator must notify the Administrator in the case where a unit switches fuels without previously having installed and certified a SO_2, NO_X and CO_2 monitoring system meeting the requirements of §§ 75.11, 75.12, and 75.13.

(4) If a unit commencing operation after January 1, 1997 initially qualifies to use the low mass emissions excepted methodology under this section and the owner or operator wants to use a low mass emissions methodology for the unit, he or she must:

(i) Keep the records specified in paragraph (c)(2) of this section, beginning with the date and hour of commencement of commercial operation, for a unit subject to an Acid Rain emission limitation, and beginning with the date and hour of the commencement of operation, for a unit subject to a NO_X mass reduction program;

(ii) Use these records to determine the cumulative heat input and SO_2, NO_X, and CO_2 mass emissions in order to continue to qualify as a low mass emission unit; and

(iii) Determine the cumulative SO_2 and NO_X mass emissions according to paragraph (c) of this section using the same procedures used after the certification deadline for the unit, for purposes of demonstrating eligibility to use the excepted methodology set forth in this section. For example, use the default emission rates in tables 1, 2 and 3 of this section or use the fuel-and-unit-specific NO_X emission rate determined according to paragraph (c)(1)(iv) of this section. The Administrator will not count SO_2 mass emissions calculated for the period between commencement of commercial operation and the certification deadline for the unit under § 75.4 against SO_2 allowances to be held in the unit account.

(5) A low mass emission unit that has been disqualified from using the low mass emissions excepted methodology may subsequently qualify again to use the low mass emissions methodology under paragraph (a)(2) of this section, provided that if such unit qualified under paragraph (a)(2)(ii) of this section, the unit may subsequently qualify again only if the unit meets the requirements of paragraph (a)(2)(i) of this section.

(c) *Low mass emissions excepted methodology, calculations, and values.*

(1) *Determination of SO_2, NO_X, and CO_2 emission rates.*

(i) Use Table 1 of this section to determine the appropriate SO_2 emission rate for use in calculating hourly SO_2 mass emissions under this section.

(ii) Use either the appropriate NO_X emission factor from Table 2 of this section, or a fuel-and-unit-specific NO_X emission rate determined according to paragraph (c)(1)(iv) of this section, to calculate hourly NO_X mass emissions under this section.

(iii) Use Table 3 of this section to determine the appropriate CO_2 emission rate for use in calculating hourly CO_2 mass emissions under this section.

(iv) In lieu of using the default NO_X emission rate from Table 2 of this section, the owner or operator may, for each fuel combusted by a low mass emission unit, determine a fuel-and-unit-specific NO_X emission rate for the purpose of calculating NO_X mass emissions under this section. This option may be used by any unit which qualifies to use the low mass emission excepted methodology under paragraph (a) of this section, and also by groups of units which combust fuel from a common source of supply and which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section to determine heat input. If this option is chosen, the following procedures shall be used.

(A) Except as otherwise provided in paragraphs (c)(1)(iv)(F) and (G) of this paragraph, determine a fuel-and-unit-specific NO_X emission rate by conducting a four load NO_X emission rate test procedure as specified in section 2.1 of appendix E to this part, for each type of fuel combusted in the unit. For a group of units sharing a common fuel supply, the appendix E testing must be performed on each individual unit in the group, unless some or all of the units in the group belong to an identical group of units, as defined in paragraph (c)(1)(iv)(B) of this section, in which case, representative testing may be conducted on units in the identical group of units, as described in paragraph (c)(1)(iv)(B) of this section. For the purposes of this section, make the following modifications to the appendix E test procedures:

(*1*) Do not measure the heat input as required under 2.1.3 of appendix E to this part.

(*2*) Do not plot the test results as specified under 2.1.6 of appendix E to this part.

(B) Representative appendix E testing may be done on low mass emission units in a group of identical units. All of the units in a group of identical units must combust the same fuel type but do not have to share a common fuel supply.

(*1*) To be considered identical, all low mass emission units must be of the same size (based on maximum rated hourly heat input), manufacturer and model, and must have the same history of modifications (e.g., have the same controls installed, the same types of burners and have undergone major overhauls at the same frequency (based on hours of operation)). Also, under similar operating conditions, the stack or turbine outlet temperature of each unit must be within ±50 degrees Fahrenheit of the average stack or turbine outlet temperature for all of the units.

(*2*) If all of the low mass emission units in the group qualify as identical, then representative testing of the units in the group may be performed according to Table 4 of this section.

(*3*) If there are only two low mass emission units in the group of identical units, the results of the representative testing under paragraph (c)(1)(iv)(B)(1) of this section may be used to establish the fuel-and-unit-specific NO_X emission rate(s) for the units. However, if there are more than two low mass emission units in the group, the testing must confirm that the units are identical by meeting the following criteria. The results of the representative testing may only be used to establish the fuel-and-unit-specific NO_X emission rate(s) for such units if the following criteria are met:

(*i*) at each of the four load levels tested, the NO_X emission rate for each tested low mass emission unit does not differ by more than ±10% from the average of the NO_X emission rates for all units tested, or;

(*ii*) if the average NO_X emission rate of all low mass emission units tested at all four load levels is less than 0.20 lb/mmBtu, an alternative criteria of ±0.020 lb/mmBtu may be use in lieu of the 10% criteria. Units must all be within +0.020 lb/mmBtu of the average from the test to be considered identical units under this section.

(*4*) If the acceptance criteria in paragaph (c)(1)(iv)(B)(3) of this section are not met then the group of low mass emission units is not considered an identical group of units and individual appendix E testing of each unit is required.

(*5*) Fuel and unit specific NO_X emission rates determined according to paragraphs (c)(1)(iv)(F) and (c)(1)(iv)(G) of this section may be used in lieu of appendix E testing for one or more low mass emission units in a group of identical units.

(C) Based on the results of the appendix E testing, determine the fuel-and-unit-specific NO_X emission rate as follows:

(*1*) For an individual low mass emission unit with no NO_X emissions controls of any kind, the highest NO_X emission rate obtained for a particular type of fuel in the appendix E test multiplied by 1.15 shall be the fuel-and-unit-specific NO_X emission rate, for that type of fuel.

(*2*) For a group of low mass emission units sharing a common fuel supply with no NO_X controls of any kind on any of the units, the highest NO_X emission rate obtained for a particular type of fuel in all of the appendix E tests of all units in the group of units sharing a common fuel supply multiplied by 1.15 shall be the fuel-and-unit-specific NO_X emission rate for each unit in the group, for that type of fuel.

(*3*) For a group of identical low mass emission units which perform representative testing according to paragraph (c)(1)(iv)(B) of this section with no NO_X controls of any kind on any of the units, the fuel-and-unit-specific NO_X emission rate for all units, for a particular type of fuel, multiplied by 1.15 shall be the highest NO_X

emission rate from any unit tested in the group, for that type of fuel.

(*4*) For an individual low mass emission unit which has NO_X emission controls of any kind, the fuel-and-unit-specific NO_X emission rate for each type of fuel combusted in the unit shall be the higher of:

(*i*) The highest emission rate from the appendix E test for that type of fuel multiplied by 1.15; or

(*ii*) 0.15 lb/mmBtu.

(*5*) For a group of low mass emission units sharing a common fuel supply, one or more of which has NO_X controls of any kind, the fuel-and-unit-specific NO_X emission rate for each unit in the group of units sharing a common fuel supply shall, for a particular type of fuel combusted by the group of units sharing a common fuel supply, shall be the higher of:

(*i*) The highest NO_X emission rate from all appendix E tests of all low mass emission units in the group for that type of fuel multiplied by 1.15; or

(*ii*) 0.15 lb/mmBtu.

(*6*) For a group of identical low mass emission units, which perform representative testing according to paragraph (c)(1)(iv)(B) of this section and have identical NO_X controls, the fuel-and-unit-specific NO_X emission rate for each unit in the group of units, for a particular type of fuel, shall be the higher of:

(*i*) The highest NO_X emission rate from all appendix E tests of all tested low mass emission units in the group of identical units for that type of fuel multiplied by 1.15; or

(*ii*) 0.15 lb/mmBtu.

(D) For each low mass emission unit, each unit in a group of units sharing a common fuel supply, or identical units for which the provisions of paragraph (c)(1)(iv) of this section are used to account for NO_X emission rate, the owner or operator shall determine a new fuel-and-unit-specific NO_X emission rate every five years, unless changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation, or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_X emission rate. If such changes occur, the fuel-and-unit-specific NO_X emission rate(s) shall be re-determined according to paragraph (c)(1)(iv) of this section. If a low mass emission unit belongs to a group of identical units and it is required to retest to determine a new fuel-and-unit-specific NO_X emission rate because of changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_X emission rate, any other unit in that group of identical units is not required to re-determine the fuel-and-unit-specific NO_X emission rate unless such unit also undergoes changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_X emission rates.

(E) Each low mass emission unit, each low mass emission unit in a group of units combusting a common fuel, or each low mass emission unit in a group of identical units for which a fuel-and-unit-specific NO_X emission rate(s) are determined shall meet the quality assurance and quality control provisions of paragraph (e) of this section.

(F) Low mass emission units may use the results of appendix E testing, if such test results are available from a test conducted no more than five years prior to the time of initial certification, to determine the appropriate fuel-and-unit-specific NO_X emission rate(s). However, fuel-and-unit-specific NO_X emission rates from historical testing may not be used longer than five years after the appendix E testing was conducted.

(G) Low mass emission units for which at least 3 years of NO_X emission rate continuous emissions monitoring system data and corresponding fuel usage data are available may determine fuel-and-unit-specific NO_X emission rates from the actual data using the following procedure. Separate the actual NO_X emission rate data into groups, according to the type of fuel combusted. Discard data from periods when multiple fuels were combusted. Each fuel-specific data set must contain at least 168 hours of data and must represent all normal operating ranges of the unit when combusting the fuel. Sort the data in each fuel-specific data set in ascending order according to NO_X emission rate. Determine the 95th percentile NO_X emission rate for each data set as defined in § 72.2 of this chapter. Use the 95th percentile value for each data set as the fuel-and-unit-specific NO_X emission rate, except that for a unit with NO_X emission controls of any kind, if the 95th percentile value is less than 0.15 lb/mmBtu, a value of 0.15 lb/mmBtu shall be used as the fuel-and-unit-specific NO_X emission rate.

(H) For low mass emission units with NO_X emission controls, the owner or operator shall, during every hour of unit operation during the test period, monitor and record parameters, as required under paragraph (e)(5) of this section, which indicate that the NO_X emission controls are operating properly. After the test period, these same parameters shall be monitored and recorded and kept for all operating hours in order to determine whether the NO_X controls are operating properly and to allow the determination of the correct NO_X emission rate as required under paragraph (c)(1)(iv) of this section.

(*1*) For low mass emission units with steam or water injection, the steam-to-fuel or water-to-fuel ratio used during the testing must be documented. The water-to-fuel or steam-to-fuel ratio must be maintained during unit operations for a unit to use the fuel and unit specific NO_X emission rate determined during the test. Owners or operators must include in the monitoring plan the acceptable range of the water-to-fuel or steam-to-fuel ratio, which will be used to indicate hourly, proper operation of the NO_X controls for each unit. The water-to-fuel or steam-to-fuel ratio shall be monitored and recorded during each hour of unit operation. If the water-to-fuel or steam-to-fuel ratio is not within the acceptable range in a given hour the fuel and unit specific NO_X emission rate may not be used for that hour.

(*2*) For low mass emission units with other types of NO_X controls, appropriate parameters and the acceptable range of the parameters which indicate hourly proper operation of the NO_X controls must be specified in the monitoring plan. These parameters shall be monitored during each subsequent operating hour. If any of these parameters are not within the acceptable range in a given operating hour, the fuel and unit specific NO_X emission rates may not be used in that hour.

(2) *Records of operating time, fuel usage, unit output and NO_X emission control operating status.* The owner or operator shall keep the following records on-site, for three years, in a form suitable for inspection:

(i) For each low mass emission unit, the owner or operator shall keep hourly records which indicate whether or not the unit operated during each clock hour of each calendar year. The owner or operator may report partial operating hours or may assume that for each hour the unit operated the operating time is a whole hour. Units using partial operating hours and the maximum rated hourly heat input to calculate heat input for each hour must report partial operating hours.

(ii) For each low mass emissions unit, the owner or operator shall keep hourly records indicating the type(s) of fuel(s) combusted in the unit during each hour of unit operation.

(iii) For each low mass emission unit using the long term fuel flow methodology under paragraph (c)(3)(ii) of this section to determine hourly heat input, the owner or operator shall keep hourly records of unit output (in megawatts or thousands of pounds of steam), for the purpose of apportioning heat input to the individual unit operating hours.

(iv) For each low mass emission unit with NO_X emission controls of any kind, the owner or operator shall keep hourly records of the hourly value of the parameter(s) specified in (c)(1)(iv)(H) of this section used to indicate proper operation of the unit's NO_X controls.

(3) *Heat input.* Hourly, quarterly and annual heat input for a low mass emission unit shall be determined using either the maximum rated hourly heat input method under paragraph (c)(3)(i) of this section or the long term fuel flow method under paragraph (c)(3)(ii) of this section.

(i) *Maximum rated hourly heat input method.* (A) For the purposes of the mass emission calculation methodology of paragraph (c)(3) of this section, the hourly heat input (mmBtu) to a low mass emission unit shall be deemed to equal the maximum rated hourly heat input, as defined in § 72.2 of this chapter, multiplied by the operating time of the unit for each hour. The owner or operator may choose to record and report partial operating hours or may assume that a unit operated for a whole hour for each hour the unit operated. However, the owner or operator of a unit may petition the Administrator under § 75.66 for a lower value for maximum rated hourly heat input than that defined in § 72.2 of this chapter. The Administrator may approve such lower value if the owner or operator demonstrates that either the maximum hourly heat input specified by the manufacturer or the highest observed hourly heat input, or both, are not representative, and such a lower value is representative, of the unit's current capabilities because modifications have been made to the unit, limiting its capacity permanently.

(B) The quarterly heat input, HI_{qtr}, in mmBtu, shall be determined using Equation LM–1:

$$HI_{qtr} = T_{qtr} \times HI_{hr} \qquad \text{(Eq. LM–1)}$$

Where:

T_{qtr} = Actual number of operating hours in the quarter (hr).

HI_{hr} = Hourly heat input under paragraph (c)(3)(i)(A) of this section (mmBtu).

(C) The year-to-date cumulative heat input (mmBtu) shall be the sum of the quarterly heat input values for all of the calendar quarters in the year to date.

(ii) *Long term fuel flow heat input method.* The owner or operator may, for the purpose of demonstrating that a low mass emission unit or group of low mass emission units sharing a common fuel supply meets the requirements of this section, use records of long-term fuel flow, to calculate hourly heat input to a low mass emission unit.

(A) This option may be used for a group of low mass emission units only if:

(*1*) The low mass emission units combust fuel from a common source of supply; and

(*2*) Records are kept of the total amount of fuel combusted by the group of low mass emission units and the hourly output (in megawatts or pounds of steam) from each unit in the group; and

(*3*) All of the units in the group are low mass emission units.

(B) For each fuel used during the quarter, the volume in standard cubic feet (for gas) or gallons (for oil) may be determined using any of the following methods;

(*1*) Fuel billing records (for low mass emission units, or groups of low mass emission units, which purchase fuel from non-affiliated sources);

(*2*) American Petroleum Institute (API) standard, American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992 (reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997; Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992) (incorporated by reference under § 75.6); or;

(*3*) A fuel flow meter certified and maintained according to appendix D to this part.

(C) For each fuel combusted during a quarter, the gross calorific value of the fuel shall be determined by either:

(*1*) Using the applicable procedures for gas and oil analysis in sections 2.2 and 2.3 of appendix D to this part. If this option is chosen the highest gross calorific value recorded during the previous calendar year shall be used; or

(*2*) Using the appropriate default gross calorific value listed in Table 5 of this section.

(D) For each type of fuel oil combusted during the quarter, the specific gravity of the oil shall be determined either by:

(*1*) Using the procedures in section 2.2.6 of appendix D to this part. If this option is chosen, use the highest specific gravity value recorded during the previous calendar year shall be used; or

(*2*) Using the appropriate default specific gravity value in Table 5 of this section.

(E) The quarterly heat input from each type of fuel combusted during the quarter by a low mass emission unit or group of low mass emission units sharing a common fuel supply shall be determined using Equation LM–2 for oil and LM–3 for natural gas.

$$HI_{fuel\text{–}qtr} = M_{qtr} \frac{GCV_{max}}{10^6}$$

Eq LM–2 (for fuel oil or diesel fuel)

Where:

$HI_{fuel\text{-}qtr}$ = Quarterly total heat input from oil (mmBtu).

M_{qtr} = Mass of oil consumed during the entire quarter, determined as the product of the volume of oil under paragraph (c)(3)(ii)(B) of this section and the specific gravity under paragraph (c)(3)(ii)(D) of this section (lb)

GCV_{max} = Gross calorific value of oil, as determined under paragraph (c)(3)(ii)(C) of this section (Btu/lb)

10^6 = Conversion of Btu to mmBtu.

$$HI_{fuel\text{–}qtr} = Q_g \frac{GCV_{max}}{10^6}$$

Eq LM–3 (for natural gas)

Where:

$HI_{fuel\text{-}qtr}$ = Quarterly heat input from natural gas (mmBtu).

Q_g = Value of natural gas combusted during the quarter, as determined under paragraph (c)(3)(ii)(B) of this section standard cubic feet (scf).

GCV_g = Gross calorific value of the natural gas combusted during the quarter, as determined under paragraph (c)(3)(ii)(C) of this section (Btu/scf)

10^6 = Conversion of Btu to mmBtu.

(F) The quarterly heat input (mmBtu) for all fuels for the quarter, $HI_{qtr\text{-}total}$, shall be the sum of the $HI_{fuel\text{-}qtr}$ values determined using Equations LM–2 and LM–3.

$$HI_{qtr-total} = \sum_{all-fuels} HI_{fuel-qtr}$$

(Eq. LM–4)

(G) The year-to-date cumulative heat input (mmBtu) for all fuels shall be the sum of all quarterly total heat input ($HI_{qtr-total}$) values for all calendar quarters in the year to date.

(H) For each low mass emission unit, each low mass emission unit of an identical group of units, or each low mass emission unit in a group of units sharing a common fuel supply, the owner or operator shall determine the quarterly unit output in megawatts or pounds of steam. The quarterly unit output shall be the sum of the hourly unit output values recorded under paragraph (c)(2) of this section and shall be determined using Equations LM–5 or LM–6.

$$MW_{qtr} = \sum_{all-hours} MW$$

Eq LM–5 (for MW output)

$$ST_{qtr} = \sum_{all-hours} ST$$

Eq LM–6 (for steam output)

Where:

MW_{qtr} = the power produced during all hours of operation during the quarter by the unit (MW)

$ST_{fuel-qtr}$ = the total quarterly steam output produced during all hours of operation during the quarter by the unit (klb)

MW = the power produced during each hour in which the unit operated during the quarter (MW).

ST = the steam output produced during each hour in which the unit operated during the quarter (klb)

(I) For a low mass emission unit that is not included in a group of low mass emission units sharing a common fuel supply, apportion the total heat input for the quarter, $HI_{qtr-total}$ to each hour of unit operation using either Equation LM–7 or LM–8:

$$HI_{hr} = HI_{qtr-total} \frac{MW_{hr}}{MW_{qtr}}$$

(Eq LM–7 for MW output)

$$HI_{hr} = HI_{qtr-total} \frac{ST_{hr}}{ST_{qtr}}$$

(Eq LM–8 for steam output)

Where:

HI_{hr} = hourly heat input to the unit (mmBtu)

MW_{hr} = hourly output from the unit (MW)

ST_{hr} = hourly steam output from the unit (klb)

(J) For each low mass emission unit that is included in a group of units sharing a common fuel supply, apportion the total heat input for the quarter, $HI_{qtr-total}$ to each hour of operation using either Equation LM–7a or LM–8a:

$$HI_{hr} = HI_{qtr-total} \frac{MW_{hr}}{\sum_{all-units} MW_{qtr}}$$

(Eq LM–7a for MW output)

$$HI_{hr} = HI_{qtr-total} \frac{ST_{hr}}{\sum_{all-units} ST_{qtr}}$$

(Eq LM–8a for steam output)

Where:

HI_{hr} = hourly heat input to the individual unit (mmBtu)

MW_{hr} = hourly output from the individual unit (MW)

ST_{hr} = hourly steam output from the individual unit (klb)

$\sum_{all-units} MW_{qtr}$ = Sum of the quarterly outputs (from Eq. LM-5) for all units in the group (MW)

$\sum_{all-units} ST_{qtr}$ = Sum of the quarterly steam outputs (from Eq. LM-6) for all units in the group (klb)

(4) *Calculation of SO_2, NO_X and CO_2 mass emissions.* The owner or operator shall, for the purpose of demonstrating that a low mass emission unit meets the requirements of this section, calculate SO_2, NO_X and CO_2 mass emissions in accordance with the following.

(i) *SO_2* mass emissions. (A) The hourly SO_2 mass emissions (lbs) for a low mass emission unit shall be determined using Equation LM–9 and the appropriate fuel-based SO_2 emission factor from Table 1 of this section for the fuels combusted in that hour. If more than one fuel is combusted in the hour, use the highest emission factor for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit.

$W_{SO2} = EF_{SO2} \times HI_{hr}$ (Eq. LM–9)

where:

W_{SO2}=Hourly SO_2 mass emissions (lbs).

EF_{SO2}=SO_2 emission factor from Table 1 of this section (lb/mmBtu).

HI_{hr}=Either the maximum rated hourly heat input under paragraph (c)(3)(i)(A) of this section or the hourly heat input under paragraph (c)(3)(ii) of this section (mmBtu).

(B) The quarterly SO_2 mass emissions (tons) for the low mass emission unit shall be the sum of all the hourly SO_2 mass emissions in the quarter, as determined under paragraph (c)(4)(i)(A) of this section, divided by 2000 lb/ton.

(C) The year-to-date cumulative SO_2 mass emissions (tons) for the low mass emission unit shall be the sum of the quarterly SO_2 mass emissions, as determined under paragraph (c)(4)(i)(B) of this section, for all of the calendar quarters in the year to date.

(ii) *NO_X mass emissions.* (A) The hourly NO_X mass emissions for the low mass emission unit (lbs) shall be determined using Equation LM–10. If more than one fuel is combusted in the hour, use the highest emission rate for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit. For low mass emission units with NO_X emission controls of any kind and for which a fuel-and-unit-specific NO_X emission rate is determined under paragraph (c)(1)(iv) of this section, for any hour in which the parameters under paragraph (c)(1)(iv)(A) of this section do not show that the NO_X emission controls are operating properly, use the NO_X emission rate from Table 2 of this section for the fuel combusted during the hour with the highest NO_X emission rate.

$W_{NOx} = EF_{NOx} \times HI_{hr}$ (Eq. LM–10)

Where:

WNO_X=Hourly NO_X mass emissions (lbs).

$EFNO_X$=Either the NO_X emission factor from Table 1b of paragraph (c)(1)(ii) of this section of this section or the fuel-and-unit-specific NO_X emission rate determined under paragraph (c)(1)(iv) of this section (lb/mmBtu).

HI_{hr}=Either the maximum rated hourly heat input from paragraph (c)(3)(i)(A) of this section or the hourly heat input as determined under paragraph(c)(3)(ii) of this section (mmBtu).

(B) The quarterly NO_X mass emissions (tons) for the low mass emission unit shall be the sum of all of the hourly NO_X mass emissions in the quarter, as determined under paragraph (c)(4)(ii)(A) of this section, divided by 2000 lb/ton.

(C) The year-to-date cumulative NO_X mass emissions (tons) for the low mass emission unit shall be the sum of the quarterly NO_X mass emissions, as determined under paragraph (c)(4)(ii)(B) of this section, for all of the calendar quarters in the year to date.

(iii) *CO_2 Mass Emissions.* (A) The hourly CO_2 mass emissions (tons) for the affected low mass emission unit shall be determined using Equation LM–11 and the appropriate fuel-based CO_2 emission factor from Table 3 of this section for the fuel being combusted in that hour. If more than one fuel is combusted in the hour, use the highest emission factor for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit.

$$WCO_2 = EFCO_2 \times HI_{hr} \qquad \text{(Eq. LM–11)}$$

Where:

WCO_2 = Hourly CO mass emissions (tons).

$EFCO_2$ = Fuel-based CO_2 emission factor from Table 3 of this section (ton/mmBtu).

HI_{hr} = Either the maximum rated hourly heat input from paragraph (c)(3)(i)(A) of this section or the hourly heat input as determined under paragraph (c)(3)(ii) of this section (mmBtu).

(B) The quarterly CO_2 mass emissions (tons) for the low mass emission unit shall be the sum of all of the hourly CO_2 mass emissions in the quarter, as determined under paragraph (c)(4)(iii)(A)of this section.

(C) The year-to-date cumulative CO_2 mass emissions (tons) for the low mass emission unit shall be the sum of all of the quarterly CO_2 mass emissions, as determined under paragraph (c)(4)(iii)(B) of this section, for all of the calendar quarters in the year to date.

(d) Each unit that qualifies under this section to use the low mass emissions methodology must follow the recordkeeping and reporting requirements pertaining to low mass emissions units in subparts F and G of this part.

(e) The quality control and quality assurance requirements in § 75.21 are not applicable to a low mass emissions unit for which the low mass emissions excepted methodology under paragraph (c) of this section is being used in lieu of a continuous emission monitoring system or an excepted monitoring system under appendix D or E to this part, except for fuel flowmeters used to meet the provisions in paragraph (c)(3)(ii) of this section. However, the owner or operator of a low mass emissions unit shall implement the following quality assurance and quality control provisions:

(1) For low mass emission units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use fuel billing records to determine fuel usage, the owner or operator shall keep, at the facility, for three years, the records of the fuel billing statements used for long term fuel flow determinations.

(2) For low mass emission units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use American Petroleum Institute (API) standard, American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992 (reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997, Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992) (incorporated by reference under § 75.6), to determine fuel usage, the owner or operator shall keep, at the facility, a copy of the standard used and shall keep records, for three years, of all measurements obtained for each quarter using the methodology.

(3) For low mass emission units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use a certified fuel flow meter to determine fuel usage, the owner or operator shall comply with the quality control quality assurance requirements for a fuel flow meter under section 2.1.6 of appendix D of this part.

(4) For each low mass emission unit for which fuel-and-unit-specific NO_X emission rates are determined in accordance with paragraph (c)(1)(iv) of this section, the owner or operator shall keep, at the facility, records which document the results of all NO_X emission rate tests conducted according to appendix E to this part. If CEMS data are used to determine the fuel-and-unit-specific NO_X emission rates under paragraph (c)(1)(iv)(G) of this section, the owner or operator shall keep, at the facility, records of the CEMS data and the data analysis performed to determine a fuel-and-unit-specific NO_X emission rate. The appendix E test records and historical CEMS data records shall be kept until the fuel and unit specific NO_X emission rates are re-determined.

(5) For each low mass emission unit for which fuel-and-unit-specific NO_X emission rates are determined in accordance with paragraph (c)(1)(iv) of this section and which have NO_X emission controls of any kind, the owner or operator shall develop and keep on-site a quality assurance plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan shall include the parameters monitored (e.g., water-to-fuel ratio) and the acceptable ranges for each parameter used to determine proper operation of the unit's NO_X controls.

TABLE 1 OF § 75.19: SO_2 EMISSION FACTORS (lb/mmBtu) FOR VARIOUS FUEL TYPES

Fuel type	SO_2 emission factors
Pipeline Natural Gas	0.0006 lb/mmBtu.
Other Natural Gas	0.06 lb/mmBtu.
Residual Oil	2.1 lb/mmBtu.
Diesel Fuel	0.5 lb/mmBtu.

TABLE 2 OF § 75.19: NO_X EMISSION RATES (lb/mmBtu) FOR VARIOUS BOILER/FUEL TYPES

Boiler type	Fuel type	NO_X emission rate
Turbine	Gas	0.7
Turbine	Oil	1.2
Boiler	Gas	1.5
Boiler	Oil	2

TABLE 3 OF § 75.19: CO_2 EMISSION FACTORS (ton/mmBtu) FOR GAS AND OIL

Fuel type	CO_2 emission factors
Natural Gas	0.059 ton/mmBtu.
Oil	0.081 ton/mmBtu.

TABLE 4 OF § 75.19: IDENTICAL UNIT TESTING REQUIREMENTS

Number of identical units in the group	Number of appendix E tests required
2	1
3 to 6	2

TABLE 4 OF § 75.19: IDENTICAL UNIT TESTING REQUIREMENTS—Continued

Number of identical units in the group	Number of appendix E tests required
7	3
>7	n tests; wherein n = number of units divided by 3 and rounded to nearest integer.

TABLE 5 OF § 75.19: DEFAULT GROSS CALORIFIC VALUES (GCVS) FOR VARIOUS FUELS

Fuel	GCV for use in equation LM–2 or LM–3
Pipeline Natural Gas	1051 Btu/scf.
Natural Gas	1118 Btu/scf.
Residual Oil	19,708 Btu/gallon.
Diesel Fuel	20,500 Btu/gallon.

TABLE 6 OF § 75.19: DEFAULT SPECIFIC GRAVITY VALUES FOR FUEL OIL

Fuel	Specific gravity (lb/gal)
Residual Oil	8.5
Diesel Fuel	7.4

13. Section 75.20 is amended by adding new paragraph (h) to read as follows:

§ 75.20 Certification and recertification procedures.

* * * * *

(h) *Initial certification and recertification procedures for low mass emission units using the excepted methodologies under § 75.19.* The owner or operator of a gas-fired or oil-fired unit using the low mass emissions excepted methodology under § 75.19 shall meet the applicable general operating requirements of § 75.10, the applicable requirements of § 75.19, and the applicable certification requirements of this paragraph.

(1) *Monitoring plan.* The designated representative shall submit a monitoring plan in accordance with §§ 75.53 and 75.62. The designated representative for an owner or operator who wishes to use fuel-and unit-specific NO_X emission rate testing for units with NO_X controls under § 75.19(c)(1)(iv) must submit in the monitoring plan the parameters monitored which will be used to determine operation of the NO_X emission controls. For units using water or steam injection to control NO_X, the water-to-fuel or steam-to-fuel range of values must be documented.

(2) *Certification application.* [reserved]

(3) *Approval of certification applications.* The provisions for the certification application formal approval process in the introductory text of paragraph (a)(4) and in paragraphs (a)(4)(i), (ii), and (iv) of this section shall apply, except that ''continuous emission or opacity monitoring system'' shall be replaced with ''excepted methodology.'' The excepted methodology shall be deemed provisionally certified for use under the Acid Rain Program, as of the following dates:

(i) For a unit that commenced operation on or before January 1, 1997, from January 1 of the year following submission of the certification application until the completion of the period for the Administrator's review; or

(ii) For a unit that commenced operation after January 1, 1997, from the date of submission of a certification application for approval to use the low mass emissions excepted methodology under § 75.19 until the completion of the period for the Administrator's review, except that the methodology may be used retrospectively until the date and hour that the unit commenced operation for purposes of demonstrating that the unit qualified to use the methodology under § 75.19(b)(4)(iii).

(4) *Disapproval of certification applications.* If the Administrator determines that the certification application does not demonstrate that the unit meets the requirements of §§ 75.19(a) and (b), the Administrator shall issue a written notice of disapproval of the certification application within 120 days of receipt. By issuing the notice of disapproval, the provisional certification is invalidated by the Administrator, and the data recorded under the excepted methodology shall not be considered valid. The owner or operator shall follow the procedures for loss of certification:

(i) The owner or operator shall substitute the following values, as applicable, for each hour of unit operation during the period of invalid data specified in paragraph (a)(4)(iii) of this section or in §§ 75.21(e) (introductory paragraph) and 75.21(e)(1): the maximum potential concentration of SO_2, as defined in section 2.1.1.1 of appendix A to this part to report SO_2 concentration; the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter to report NO_X emission rate; the maximum potential flow rate, as defined in section 2.1 of appendix A to this part to report volumetric flow; or the maximum CO_2 concentration used to determine the maximum potential concentration of SO_2 in section 2.1.1.1 of appendix A to this part to report CO_2 concentration data. For a unit subject to a State or federal NO_X mass reduction program where the owner or operator intends to monitor NO_X mass emissions with a NO_X pollutant concentration monitor and a flow monitoring system, substitute for NO_X concentration using the maximum potential concentration of NO_X, as defined in section 2.1.2.1 of appendix A to this part, and substitute for volumetric flow using the maximum potential flow rate, as defined in section 2.1 of appendix A to this part. The owner or operator shall substitute these values until such time, date, and hour as a continuous emission monitoring system or excepted monitoring system, where applicable, is installed and provisionally certified;

(ii) The designated representative shall submit a notification of certification test dates, as specified in § 75.61(a)(1)(ii), and a new certification application according to the procedures in paragraph (a)(2) of this section; and

(iii) The owner or operator shall install and provisionally certify continuous emission monitoring systems or excepted monitoring systems, where applicable, two calendar quarters from the end of the quarter in which the unit no longer qualifies as a low mass emissions unit.

14. Section 75.24 is amended by revising paragraph (d) to read as follows:

§ 75.24 Out-of-control periods.

* * * * *

(d) When the bias test indicates that an SO_2 monitor, a volumetric flow monitor, a NO_X continuous emission monitoring system or a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71(a)(2), is biased low (i.e., the arithmetic mean of the differences between the reference method value and the monitor or monitoring system measurements in a relative accuracy test audit exceed the bias statistic in section 7 of appendix A to this part), the owner or operator shall adjust the monitor or continuous emission monitoring system to eliminate the cause of bias such that it passes the bias test, or calculate and use the bias adjustment factor as specified in section 2.3.3 of appendix B to this part and in accordance with § 75.7.

* * * * *

16. Subpart H is added to part 75 to read as follows:

Subpart H—NO_X Mass Emissions Provisions

Subpart H—NO_X Mass Emissions Provisions

§ 75.70 NO_X mass emissions provisions.

(a) *Applicability*. The owner or operator of a unit shall comply with the requirements of this subpart to the extent that compliance is required by an applicable State or federal NO_X mass emission reduction program that incorporates by reference, or otherwise adopts the provisions of, this subpart.

(1) For purposes of this subpart, the term ''affected unit'' shall mean any unit that is subject to a State or federal NO_X mass emission reduction program requiring compliance with this subpart, the term ''nonaffected unit'' shall mean any unit that is not subject to such a program, the term ''permitting authority'' shall mean the permitting authority under an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart, and the term ''designated representative'' shall mean the responsible party under the applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(2) In addition, the provisions of subparts A, C, D, E, F, and G and appendices A through G of this part applicable to NO_X concentration, flow rate, NO_X emission rate and heat input, as set forth and referenced in this subpart, shall apply to the owner or operator of a unit required to meet the requirements of this subpart by a State or federal NO_X mass emission reduction program. When applying these requirements, the term ''affected unit'' shall mean any unit that is subject to a State or federal NO_X mass emission reduction program requiring compliance with this subpart, the term ''permitting authority'' shall mean the permitting authority under an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart, and the term ''designated representative'' shall mean the responsible party under the applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart. The requirements of this part for SO_2, CO_2 and opacity monitoring, recordkeeping and reporting do not apply to units that are subject to a State or federal NO_X mass emission reduction program only and are not affected units with an Acid Rain emission limitation.

(b) *Compliance dates.* The owner or operator of an affected unit shall meet the compliance deadlines established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(c) *Prohibitions.* (1) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained prior written approval in accordance with paragraph (h) of this section.

(2) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall operate the unit so as to discharge, or allow to be discharged emissions of NO_X to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this part, except as provided in § 75.74.

(3) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the provisions of this part applicable to monitoring systems under § 75.71, except as provided in § 75.74.

(4) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved emission monitoring system under this part, except under any one of the following circumstances:

(i) During the period that the unit is covered by a retired unit exemption that is in effect under the State or federal NO_X mass emission reduction program that adopts the requirements of this subpart;

(ii) The owner or operator is monitoring NO_X mass emissions from the affected unit with another certified monitoring system approved, in accordance with the provisions of paragraph (d) of this section; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system in accordance with § 75.61.

(d) *Initial certification and recertification procedures.* (1) The owner or operator of an affected unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures of this part, except that the owner or operator shall meet any additional requirements set forth in an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(2) The owner or operator of an affected unit that is not subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart. The owner or operator of an affected unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart for any additional NO_X-diluent CEMS, flow monitors, diluent monitors or NO_X concentration monitoring system required under the NO_X mass emissions provisions of § 75.71 or the common stack provisions in § 75.72.

(e) *Quality assurance and quality control requirements.* For units that use continuous emission monitoring systems to account for NO_X mass emissions, the owner or operator shall meet the quality assurance and quality control requirements in § 75.21 that apply to NO_X-diluent continuous emission monitoring systems, flow monitoring systems, NO_X concentration monitoring systems, and diluent monitors under § 75.71. A NO_X concentration monitoring system for determining NO_X mass emissions in accordance with § 75.71 shall meet the same certification testing requirements, quality assurance requirements, and bias test requirements as are specified in this part for an SO_2 pollutant concentration monitor. Units using excepted methods under § 75.19 shall meet the applicable quality assurance requirements of that section, and units using excepted monitoring methods under appendix D and E to this part shall meet the applicable quality assurance requirements of those appendices.

(f) *Missing data procedures.* Except as provided in § 75.34 and paragraph (g) of this section, the owner or operator shall provide substitute data from monitoring systems required under § 75.71 for each affected unit as follows:

(1) For an owner or operator using a continuous emissions monitoring system, substitute for missing data in accordance with the missing data procedures in subpart D of this part whenever the unit combusts fuel and:

(i) A valid quality assured hour of NO_X emission rate data (in lb/mmBtu) has not been measured and recorded for a unit by a certified NO_X-diluent continuous emission monitoring system or by an approved monitoring system under subpart E of this part;

(ii) A valid quality assured hour of flow data (in scfh) has not been measured and recorded for a unit from a certified flow monitor or by an approved alternative monitoring system under subpart E of this part; or

(iii) A valid quality assured hour of heat input data (in mmBtu) has not been measured and recorded for a unit from a certified flow monitor and a certified diluent (CO_2 or O_2) monitor or by an approved alternative monitoring system under subpart E of this part or by an accepted monitoring system under appendix D to this part, where heat input is required either for calculating NO_X mass or allocating allowances under the applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart; or

(iv) A valid, quality-assured hour of NO_X concentration data (in ppm) has not been measured and recorded by a certified NO_X concentration monitoring system, or by an approved alternative monitoring method under subpart E of this part, where the owner or operator chooses to use a NO_X concentration monitoring system with a volumetric flow monitor, and without a diluent monitor, to calculate NO_X mass emissions. The initial missing data procedures for determining monitor data availability and the standard missing data procedures for a NO_X concentration monitoring system shall be the same as the procedures specified for a NO_X-diluent continuous emission monitoring system under §§ 75.31, 75.32 and 75.33, except that the phrase ''NO_X concentration monitoring system'' shall be substituted for the phrase ''NO_X continuous emission monitoring system'', the phrase ''NO_X concentration'' shall be substituted for ''NO_X emission rate'; and the phrase ''maximum potential NO_X concentration, as defined in section 2.1.2.1 of appendix A of this part'' shall be substituted for the phrase ''maximum potential NO_X emission rate, as defined in § 72.2 of this chapter''.

(2) For an owner or operator using an excepted monitoring system under appendix D or E of this part, substitute for missing data in accordance with the missing data procedures in section 2.4 of appendix D to this part or in section 2.5 of appendix E to this part whenever the unit combusts fuel and:

(i) A valid, quality-assured hour of fuel flow rate data has not been measured and recorded by a certified fuel flowmeter that is part of an excepted monitoring system under appendix D or E of this part; or

(ii) A fuel sample value for gross calorific value, or if necessary, density or specific gravity, from a sample taken an analyzed in accordance with appendix D of this part is not available; or

(iii) A valid, quality-assured hour of NO_X emission rate data has not been obtained according to the procedures and specifications of appendix E to this part.

(g) *Reporting data prior to initial certification.* If the owner or operator of an affected unit has not successfully completed all certification tests required by the State or federal NO_X mass emission reduction program that adopts the requirements of this subpart by the applicable date required by that program, he or she shall determine, record and report hourly data prior to initial certification using one of the following procedures, consistent with the monitoring equipment to be certified:

(1) For units that the owner or operator intends to monitor for NO_X mass emissions using NO_X emission rate and heat input, the maximum potential NO_X emission rate and the maximum potential hourly heat input of the unit, as defined in § 72.2 of this chapter.

(2) For units that the owner or operator intends to monitor for NO_X mass emissions using a NO_X concentration monitoring system and a flow monitoring system, the maximum potential concentration of NO_X and the maximum potential flow rate of the unit under section 2.1 of Appendix A of this part;

(3) For any unit, the reference methods under § 75.22 of this part.

(4) For any unit using the low mass emission excepted monitoring methodology under § 75.19, the procedures in paragraphs (g)(1) or (2) of this section.

(5) Any unit using the procedures in paragraph (g)(2) of this section that is required to report heat input for purposes of allocating allowances shall also report the maximum potential hourly heat input of the unit, as defined in § 72.2 of this chapter.

(h) *Petitions.* (1) The designated representative of an affected unit that is subject to an Acid Rain emissions limitation may submit a petition to the Administrator requesting an alternative to any requirement of this subpart. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart. Use of an alternative to any requirement of this subpart is in accordance with this subpart and with such State or federal NO_X mass emission reduction program only to the extent that the petition is approved by the Administrator, in consultation with the permitting authority.

(2) Notwithstanding paragraph (h)(1) of this section, petitions requesting an alternative to a requirement concerning any additional CEMS required solely to meet the common stack provisions of § 75.72 shall be submitted to the permitting authority and the Administrator and shall be governed by paragraph (h)(3)(ii) of this section. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(3)(i) The designated representative of an affected unit that is not subject to an Acid Rain emissions limitation may submit a petition to the permitting authority and the Administrator requesting an alternative to any requirement of this subpart. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(ii) Use of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that it is approved by the Administrator and by the permitting authority if required by an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

§ 75.71 Specific provisions for monitoring NO_X emission rate and heat input for the purpose of calculating NO_X mass emissions.

(a) *Coal-fired units.* The owner or operator of a coal-fired affected unit shall either:

(1) Meet the general operating requirements in § 75.10 for a NO_X-diluent continuous emission monitoring system (consisting of a NO_X pollutant concentration monitor, an O_2- or CO_2-diluent gas monitor, and a data acquisition and handling system) to measure NO_X emission rate and for a flow monitoring system and an O_2- or CO_2-diluent gas monitor to measure heat input, except as provided in accordance with subpart E of this part; or

(2) Meet the general operating requirements in § 75.10 for a NO_X concentration monitoring system (consisting of a NO_X pollutant concentration monitor and a data acquisition and handling system) to measure NO_X concentration and for a flow monitoring system. In addition, if heat input is required to be reported under the applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart, the owner or operator also must meet the general operating requirements for a flow monitoring system and an O_2- or CO_2-diluent gas monitor to measure heat input, or, if applicable, use the procedures in appendix D to this part. These requirements must be met, except as provided in accordance with subpart E of this part.

(b) *Moisture correction.* If a correction for the stack gas moisture content is needed to properly calculate the NO_X emission rate in lb/mmBtu (i.e., if the NO_X pollutant concentration monitor measures on a different moisture basis from the diluent monitor) or NO_X mass emissions in tons (i.e., if the NO_X concentration monitoring system or diluent monitor measures on a different moisture basis from the flow rate monitor), the owner or operator of an affected unit shall account for the moisture content of the flue gas on a continuous basis in accordance with § 75.11(b) except that the term ''SO_2'' shall be replaced by the term ''NO_X'.

(c) *Gas-fired nonpeaking units or oil-fired nonpeaking units.* The owner or operator of an affected unit that, based on information submitted by the designated representative in the monitoring plan, qualifies as a gas-fired or oil-fired unit but not as a peaking unit, as defined in § 72.2 of this chapter, shall either:

(1) Meet the requirements of paragraph (a) of this section and, if applicable, paragraph (b) of this section; or

(2) Meet the general operating requirements in § 75.10 for a NO_X-diluent continuous emission monitoring system, except as provided in accordance with subpart E of this part, and use the procedures specified in appendix D to this part for determining hourly heat input. However, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart, except as provided in § 75.72(a); or

(3) Meet the requirements of the low mass emission excepted methodology under paragraph (e)(2) of this section and under § 75.19, if applicable.

(d) *Gas-fired or oil-fired peaking units.* The owner or operator of an affected unit that qualifies as a peaking unit and as either gas-fired or oil-fired, as defined in § 72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan, shall either:

(1) Meet the requirements of paragraph (c) of this section; or

(2) Use the procedures in appendix D to this part for determining hourly heat input and the procedures specified in appendix E to this part for estimating hourly NO_X emission rate. However, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart except for units using an excepted monitoring system under appendix E to this part and except as provided in § 75.72(a). In addition, if after certification of an excepted monitoring system under appendix E to this part, a unit's operations exceed a capacity factor of 20.0 percent in any calender year or exceed a capacity factor of 10.0 percent averaged over three years, the owner or operator shall meet the requirements of paragraph (c) of this section or, if applicable, paragraph (e) of this section, by no later than December 31 of the following calender year.

(e) *Low mass emissions units.* Notwithstanding the requirements of paragraphs (c) and (d) of this section, the owner or operator of an affected unit that qualifies as a low mass emissions unit under § 75.19(a) shall comply with one of the following:

(1) Meet the applicable requirements specified in paragraphs (c) or (d) of this section; or

(2) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly emission rate, hourly heat input, and hourly NO_X mass emissions.

(f) *Other units.* The owner or operator of an affected unit that combusts wood, refuse, or other materials shall comply with the monitoring provisions specified in paragraph (a) of this section and, where applicable, paragraph (b) of this section.

§ 75.72 Determination of NO_X mass emissions.

Except as provided in paragraphs (e) and (f) of this section, the owner or operator of an affected unit shall calculate hourly NO_X mass emissions (in lbs) by multiplying the hourly NO_X emission rate (in lbs/mmBtu) by the hourly heat input (in mmBtu/hr) and the hourly operating time (in hr). The owner or operator shall also calculate quarterly and cumulative year-to-date NO_X mass emissions and cumulative NO_X mass emissions for the ozone season (in tons) by summing the hourly NO_X mass emissions according to the procedures in section 8 of appendix F to this part.

(a) *Unit utilizing common stack with other affected unit(s).* When an affected unit utilizes a common stack with one or more affected units, but no nonaffected units, the owner or operator shall either:

(1) Record the combined NO_X mass emissions for the units exhausting to the common stack, install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system in the common stack, and either:

(i) Install, certify, operate, and maintain a flow monitoring system at the common stack. The owner or operator also shall provide heat input values for each unit, either by monitoring each unit individually using a flow monitor and a diluent monitor or by apportioning heat input according to the procedures in § 75.16(e)(5); or

(ii) If any of the units using the common stack are eligible to use the procedures in appendix D to this part,

(A) Use the procedures in appendix D to this part to determine heat input for that unit; and

(B) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack for each remaining unit; or

(2) Install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system in the duct to the common stack from each unit and either:

(i) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack from each unit; or

(ii) For any unit using the common stack and eligible to use the procedures in appendix D to this part,

(A) Use the procedures in appendix D to determine heat input for that unit; and

(B) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack for each remaining unit.

(b) *Unit utilizing common stack with nonaffected unit(s).* When one or more affected units utilizes a common stack with one or more nonaffected units, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_X-diluent continuous emission monitoring system in the duct to the common stack from each affected unit; and

(i) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack from each affected unit; or

(ii) For any affected unit using the common stack and eligible to use the procedures in appendix D to this part,

(A) Use the procedures in appendix D to determine heat input for that unit; however, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart; and

(B) Install, certify, operate, and maintain a flow monitoring system in the duct to the common stack for each remaining affected unit that exhausts to the common stack; or

(2) Install, certify, operate, and maintain a NO_X-diluent continuous emission monitoring system in the common stack; and

(i) Designate the nonaffected units as affected units in accordance with the applicable State or federal NO_X mass emissions reduction program and meet the requirements of paragraph (a)(1) of this section; or

(ii) Install, certify, operate, and maintain a flow monitoring system in the common stack and a NO_X-diluent continuous emission monitoring system in the duct to the common stack from each nonaffected unit. The designated representative shall submit a petition to the permitting authority and the Administrator to allow a method of calculating and reporting the NO_X mass emissions from the affected units as the difference between NO_X mass emissions measured in the common stack and NO_X mass emissions measured in the ducts of the nonaffected units, not to be reported as an hourly value less than zero. The permitting authority and the Administrator may approve such a method whenever the designated representative demonstrates, to the satisfaction of the permitting authority and the Administrator, that the method ensures that the NO_X mass emissions from the affected units are not underestimated. In addition, the owner or operator shall also either:

(A) Install, certify, operate, and maintain a flow monitoring system in the duct from each nonaffected unit or,

(B) For any nonaffected unit exhausting to the common stack and otherwise eligible to use the procedures in appendix D to this part, determine heat input using the procedures in appendix D for that unit. However, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart. For any remaining nonaffected unit that exhausts to the common stack, install, certify, operate, and maintain a flow monitoring system in the duct to the common stack; or

(iii) Install a flow monitoring system in the common stack and record the combined emissions from all units as the combined NO_X mass emissions for the affected units for recordkeeping and compliance purposes; or

(iv) Submit a petition to the permitting authority and the Administrator to allow use of a method for apportioning NO_X mass emissions measured in the common stack to each of the units using the common stack and for reporting the NO_X mass emissions. The permitting authority and the Administrator may approve such a method whenever the designated representative demonstrates, to the satisfaction of the permitting authority and the Administrator, that the method ensures that the NO_X mass emissions from the affected units are not underestimated.

(c) *Unit with bypass stack.* Whenever any portion of the flue gases from an affected unit can be routed to avoid the installed NO_X-diluent continuous emissions monitoring system or NO_X concentration monitoring system, the owner and operator shall either:

(1) Install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system and a flow monitoring system on the bypass flue, duct, or stack gas stream and calculate NO_X mass emissions for the unit as the sum of the emissions recorded by all required monitoring systems; or

(2) Monitor NO_X mass emissions on the bypass flue, duct, or stack gas stream using the reference methods in § 75.22(b) for NO_X concentration, flow, and diluent, or NO_X concentration and flow, and calculate NO_X mass emissions for the unit as the sum of the emissions recorded by the installed monitoring systems on the main stack and the emissions measured by the reference method monitoring systems.

(d) *Unit with multiple stacks.* Notwithstanding § 75.17(c), when the flue gases from a affected unit discharge to the atmosphere through more than one stack, or when the flue gases from a unit subject to a NO_X mass emission reduction program utilize two or more ducts feeding into two or more stacks (which may include flue gases from other affected or nonaffected unit(s)), or when the flue gases from an affected unit utilize two or more ducts feeding into a single stack and the owner or operator chooses to monitor in the ducts rather than in the stack, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_X-diluent continuous emission monitoring system and a flow monitoring system in each duct feeding into the stack or stacks and determine NO_X mass emissions from each affected unit using the stack or stacks as the sum of the NO_X mass emissions recorded for each duct; or

(2) Install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system and a flow monitoring system in each stack, and determine NO_X mass emissions from the affected unit using the sum of the NO_X mass emissions recorded for each stack, except that where another unit also exhausts flue gases to one or more of the stacks, the owner or operator shall also comply with the applicable requirements of paragraphs (a) and (b) of this section to determine and record NO_X mass emissions from the units using that stack; or

(3) If the unit is eligible to use the procedures in appendix D to this part, install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system in one of the ducts feeding into the stack or stacks and use the procedures in appendix D to this part to determine heat input for the unit, provided that:

(i) There are no add-on NO_X controls at the unit;

(ii) The unit is not capable of emitting solely through an unmonitored stack (e.g., has no dampers); and

(iii) The owner or operator of the unit demonstrates to the satisfaction of the permitting authority and the Administrator that the NO_X emission rate in the monitored duct or stack is representative of the NO_X emission rate in each duct or stack.

(e) *Units using a NO_X concentration monitoring system and a flow monitoring system to determine NO_X mass.* The owner or operator may use a NO_X concentration monitoring system and a flow monitoring system to determine NO_X mass emissions in paragraphs (a) through (d) of this section (in place of a NO_X-diluent continuous emission monitoring system and a flow monitoring system). When using this approach, calculate NO_X mass according to sections 8.2 and 8.3 in appendix F of this part. In addition, if an applicable

State or federal NO_X mass reduction program requires determination of a unit's heat input, the owner or operator must either:

(1) Install, certify, operate, and maintain a CO_2 or O_2 diluent monitor in the same location as each flow monitoring system. In addition, the owner or operator must provide heat input values for each unit utilizing a common stack by either:

(i) Apportion heat input from the common stack to each unit according to § 75.16(e)(5), where all units utilizing the common stack are affected units, or

(ii) Measure heat input from each affected unit, using a flow monitor and a CO_2 or O_2 diluent monitor in the duct from each affected unit; or

(2) For units that are eligible to use appendix D to this part, use the procedures in appendix D to this part to determine heat input for the unit. However, the use of a fuel flowmeter in a common pipe header and the provisions of sections 2.1.2.1 and 2.1.2.2 of appendix D of this part are not applicable to any unit that is using the provisions of this subpart to monitor, record, and report NO_X mass emissions under a State or federal NO_X mass emission reduction program and that shares a common pipe or a common stack with a nonaffected unit.

(f) *Units using the low mass emitter excepted methodology under § 75.19.* For units that are using the low mass emitter excepted methodology under § 75.19, calculate ozone season NO_X mass emissions by summing all of the hourly NO_X mass emissions in the ozone season, as determined under paragraph § 75.19(c)(4)(ii)(A) of this section, divided by 2000 lb/ton.

(g) *Procedures for apportioning heat input to the unit level.* If the owner or operator of a unit using the common stack monitoring provisions in paragraphs (a) or (b) of this section does not monitor and record heat input at the unit level and the owner or operator is required to do so under an applicable State or federal NO_X mass emission reduction program, the owner or operator should apportion heat input from the common stack to each unit according to § 75.16(e)(5).

§ 75.73 Recordkeeping and reporting. [Reserved]

§ 75.74 Annual and ozone season monitoring and reporting requirements.

(a) *Annual monitoring requirement.* (1) The owner or operator of an affected unit subject both to an Acid Rain emission limitation and to a State or federal NO_X mass reduction program that adopts the provisions of this part must meet the requirements of this part during the entire calendar year.

(2) The owner or operator of an affected unit subject to a State or federal NO_X mass reduction program that adopts the provisions of this part and that requires monitoring and reporting of hourly emissions on an annual basis must meet the requirements of this part during the entire calendar year.

(b) *Ozone season monitoring requirements.* The owner or operator of an affected unit that is not required to meet the requirements of this subpart on an annual basis under paragraph (a) of this section may either:

(1) Meet the requirements of this subpart on an annual basis; or

(2) Meet the requirements of this part during the ozone season, except as specified in paragraph (c) of this section.

(c) If the owner or operator of an affected unit chooses to meet the requirements of this subpart on less than an annual basis in accordance with paragraph (b)(2) of this section, then:

(1) The owner or operator of a unit that uses continuous emissions monitoring systems to meet any of the requirements of this subpart must perform recertification testing of all continuous emission monitoring systems under § 75.20(b). If the owner or operator has not successfully completed all recertification tests by the first hour of unit operation during the ozone season each year, the owner or operator must substitute for data following the procedures of § 75.20(b).

(2) The owner or operator is required to operate and maintain continuous emission monitoring systems and perform quality assurance and quality control procedures under § 75.21 and appendix B of this part each year from the time the continuous emission monitoring system is initially certified or is recertified under paragraph (c)(1) of this section through September 30. Records related to the quality assurance/quality control program must be kept in a form suitable for inspection on a year-round basis.

(3) The owner or operator of a unit using the procedures in appendix D of this part to determine heat input is required to operate or maintain fuel flowmeters only during the ozone season, except that for purposes of determining the deadline for the next periodic quality assurance test on the fuel flowmeter, the owner or operator shall count all quarters during the year when the fuel flowmeter is used, not just quarters in the ozone season. The owner or operator shall record and the designated representative shall report the number of quarters when a fuel is combusted for each fuel flowmeter.

(4) The owner or operator of a unit using the procedures in appendix D of this part to determine heat input is only required to sample fuel during the ozone season, except that:

(i) The owner or operator of a diesel-fired unit that performs sampling from the fuel storage tank upon delivery must sample the tank between the date and hour of the most recent delivery before the first date and hour that the unit operates in the ozone season and the first date and hour that the unit operates in the ozone season.

(ii) The owner or operator of a diesel-fired unit that performs sampling upon delivery from the delivery vehicle must ensure that all shipments received during the calendar year are sampled.

(iii) The owner or operator of a unit that performs sampling on each day the unit combusts fuel oil or that performs oil sampling continuously must sample the fuel oil starting on the first day the unit operates during the ozone season. The owner or operator then shall use that sampled value for all hours of combustion during the first day of unit operation, continuing until the date and hour of the next sample.

(5) The owner or operator is required to record and report the hourly data required by this subpart for the longer of:

(i) The period of time that the owner or operator of the unit is required to perform the quality assurance and quality control procedures of § 75.21 and appendix B of this part under paragraph (c)(2) of this section; or

(ii) The period of time of May 1 through September 30.

(6) The owner or operator shall use quality-assured data, in accordance with paragraph (c)(2) or (c)(3) of this section, in the substitute data procedures under subpart D of this part and section 2.4 of appendix D of this part.

(i) The lookback periods (e.g., 2160 quality-assured monitor operating hours for a NO_X-diluent continuous emission monitoring system, a NO_X concentration monitoring system, or a flow monitoring system) used to calculate missing data must include only data from periods when the monitors were quality assured under paragraph (c)(2) or (c)(3) of this section.

(ii) If the NO_X emission rate or NO_X concentration of the unit was consistently lower in the previous ozone season because the unit combusted a fuel that produces less NO_X than the fuel currently being combusted or because the unit's add-on emission controls are not operating properly, then the owner or operator shall not use the missing data procedures of §§ 75.31 through 75.33. Instead, the owner or operator shall substitute the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter, from a NO_X-diluent continuous emission monitoring system, or the maximum potential concentration of NO_X, as defined in section 2.1.2.1 of appendix A to this part, from a NO_X concentration monitoring system. The owner or operator shall substitute these maximum potential values for each hour of missing NO_X data, from completion of recertification testing until the earliest of:

(A) 720 quality-assured monitor operating hours after the completion of recertification testing (not to go beyond September 30 of that ozone season), or

(B) For a unit that changed fuels, the first hour when the unit combusts a fuel that produces the same or less NO_X than the fuel combusted in the previous ozone season, or

(C) For a unit with add-on emission controls that are not operating properly, the first hour when the add-on emission controls operate properly.

(7) The owner or operator of a unit with NO_X add-on emission controls or a unit capable of combusting more than one fuel shall keep records during ozone season in a form suitable for inspection to demonstrate that the typical NO_X emission rate or NO_X concentration during the prior ozone season(s) included in the missing data lookback period is representative of the ozone season in which missing data are substituted and that use of the missing data procedures will not systematically underestimate NO_X mass emissions. These records shall include:

(i) For units that can combust more than one fuel, the fuel or fuels combusted each hour; and

(ii) For units with add-on emission controls, the range of operating parameters for add-on emission controls, as described in § 75.34(a) and information for verifying proper operation of the add-on emission controls, as described in § 75.34(d).

(8) The designated representative shall certify with each quarterly report that NO_X emission rate values or NO_X concentration values substituted for missing data under subpart D of this part are calculated using only values from an ozone season, that substitute values measured during the prior ozone season(s) included in the missing data lookback period are representative of the ozone season in which missing data are substituted, and that NO_X emissions are not systematically underestimated.

(9) Units may qualify to use the low mass emission excepted monitoring methodology in § 75.19 on an ozone season basis. In order to be allowed to use this methodology, a unit may not emit more than 25 tons of NO_X per ozone season. The owner or operator of the unit shall meet the requirements of § 75.19, with the following exceptions:

(i) The phrase ''50 tons of NO_X annually'' shall be replaced by the phrase ''25 tons of NO_X during the ozone season.''

(ii) If any low mass emission unit fails to provide a demonstration that its ozone season NO_X mass emissions are less than 25 tons, than the unit is disqualified from using the methodology. The owner or operator must install and certify any equipment needed to ensure that the unit is monitoring using an acceptable methodology by May 1 of the following year.

(10) Units may qualify to use the optional NO_X mass emissions estimation protocol for gas-fired peaking units and oil-fired peaking units in appendix E to this part on an ozone season basis. In order to be allowed to use this methodology, the unit must meet the definition of peaking unit in § 72.2 of this part, except that the word ''calender year'' shall be replaced by the word ''ozone season'' and the word annual in the definition of the term ''capacity factor'' in § 72.2 of this part, shall be replaced by the word ''ozone season''.

§ 75.75 Additional ozone season calculation procedures for special circumstances.

(a) The owner or operator of a unit that is required to calculate ozone season heat input for purposes of providing data needed for determining allocations, shall do so by summing the unit's hourly heat input determined according to the procedures in this part for all hours in which the unit operated during the ozone season.

(b) The owner or operator of a unit that is required to determine ozone season NO_X emission rate (in lbs/mmBtu) shall do so by dividing ozone season NO_X mass emissions(in lbs) determined in accordance with this subpart, by heat input determined in accordance with paragraph (a) of this section.

17. Section 3 of appendix A to part 75 is amended by revising the title of section 3.3.2 and by adding and reserving section 3.3.6, by adding new section 3.3.7 and by revising section 3.4.1 to read as follows:

APPENDIX A TO PART 75—SPECIFICATIONS AND TEST PROCEDURES

* * * * *

3. PERFORMANCE SPECIFICATIONS

* * * * *

3.3.2 RELATIVE ACCURACY FOR NO_X DILUENT CONTINUOUS EMISSION MONITORING SYSTEMS

* * * * *

3.3.6 [Reserved]

3.3.7 RELATIVE ACCURACY FOR NO_X CONCENTRATION MONITORING SYSTEMS

The following requirement applies only to NO_X concentration monitoring systems (i.e., NO_X pollutant concentration monitors) that are used to determine NO_X mass emissions, where the owner or operator elects to monitor and report NO_X mass emissions using a NO_X concentration monitoring system and a flow monitoring system.

The relative accuracy for NO_X concentration monitoring systems shall not exceed 10.0 percent.

* * * * *

3.4.1 SO_2 POLLUTANT CONCENTRATION MONITORS, NO_X CONCENTRATION MONITORING SYSTEMS AND NO_X-DILUENT CONTINUOUS EMISSION MONITORING SYSTEMS

SO_2 pollutant concentration monitors and NO_X emission rate continuous emissions monitoring systems shall not be biased low as determined by the test procedure in section 7.6 of this appendix. NO_X concentration monitoring systems used to determine NO_X mass emissions, as defined in § 75.71, shall not be biased low as determined by the test procedure in section 7.6 of this appendix. The bias specification applies to all SO_2 pollutant concentration monitors, including those measuring an average SO_2 concentration of 250.0 ppm or less, and to all NO_X-diluent continuous emission monitoring systems, including those measuring an average NO_X emission rate of 0.20 lb/mmBtu or less.

* * * * *

18. Section 6 of appendix A to part 75 is amended by revising the first sentence of the introductory text of section 6.5 and by adding a new sentence after the first sentence, to read as follows:

* * * * *

6.5 Relative Accuracy and Bias Tests

Perform relative accuracy test audits for each CO_2 and SO_2 pollutant concentration monitor; each NO_X concentration monitoring system used to determine NO_X mass emissions; each O_2 monitor used to calculate heat input or CO_2 concentration; each SO_2-diluent continuous emission monitoring system (lb/mmBtu) used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999; each flow monitor; and each NO_X-diluent continuous emission monitoring system. Perform relative accuracy test audits for each NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71(a)(2), using the same general procedures as for CO_2 and

SO_2 pollutant concentration monitors; however, use the reference methods for NO_X concentration listed in section 6.5.10 of this appendix. * * *

* * * * *

19. Section 7 of appendix A is amended by revising the introductory text of section 7.6 and by adding three sentences to the end of section 7.6.5 to read as follows:

* * * * *

7.6 Bias Test and Adjustment Factor

Test the relative accuracy test audit data sets for bias for SO_2 pollutant concentration monitors; flow monitors; NO_X concentration monitoring systems used to determine NO_X mass emissions, as defined in § 75.71(a)(2); and NO_X-diluent continuous emission monitoring systems using the procedures outlined below.

* * * * *

7.6.5 Bias Adjustment

* * * In addition, use the adjusted NO_X concentration and flow rate values in computing substitution values in the missing data procedure, as specified in subpart D of this part, and in reporting the NO_X concentration and the flow rate when used to calculate NO_X mass emissions, as specified in subpart H of this part. Do not use an adjusted NO_X concentration value to calculate NO_X emission rate using Equations F–5 or F–6 of Appendix F of this part. When monitoring NO_X emission rate and heat input, use the adjusted NO_X emission rate and flow rate values in computing substitution values in the missing data procedure, as specified in subpart D of this part, and in reporting the NO_X emission rate and the heat input.

* * * * *

20. Appendix C to part 75 is amended by revising sections 2.1, 2.2.2, 2.2.3, 2.2.5, and 2.2.6 to read as follows:

APPENDIX C TO PART 75—MISSING DATA ESTIMATION PROCEDURES

* * * * *

2.1 Applicability

This procedure is applicable for data from all affected units for use in accordance with the provisions of this part to provide substitute data for volumetric flow rate (scfh), NO_X emission rate (in lb/mmBtu), and NO_X concentration data (in ppm) from NO_X concentration monitoring systems used to determine NO_X mass emissions.

2.2 Procedure

2.2.1 * * *

2.2.2 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_X continuous emission monitoring system (or a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71, for each hour of unit operation record a number, 1 through 10 (or 1 through 20 for flow at common stacks), that identifies the operating load range corresponding to the integrated hourly gross load of the unit(s) recorded for each unit operating hour.

2.2.3 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_X continuous emission monitoring system (or a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71 and continuing thereafter, the data acquisition and handling system must be capable of calculating and recording the following information for each unit operating hour of missing flow or NO_X data within each identified load range during the shorter of: (1) the previous 2,160 quality assured monitor operating hours (on a rolling basis), or (2) all previous quality assured monitor operating hours.

2.2.3.1 Average of the hourly flow rates reported by a flow monitor, in scfh.

2.2.3.2 The 90th percentile value of hourly flow rates, in scfh.

2.2.3.3 The 95th percentile value of hourly flow rates, in scfh.

2.2.3.4 The maximum value of hourly flow rates, in scfh.

2.2.3.5 Average of the hourly NO_X emission rate, in lb/mmBtu, reported by a NO_X continuous emission monitoring system.

2.2.3.6 The 90th percentile value of hourly NO_X emission rates, in lb/mmBtu.

2.2.3.7 The 95th percentile value of hourly NO_X emission rates, in lb/mmBtu.

2.2.3.8 The maximum value of hourly NO_X emission rates, in lb/mmBtu.

2.2.3.9 Average of the hourly NO_X pollutant concentration, in ppm, reported by a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71.

2.2.3.10 The 90th percentile value of hourly NO_X pollutant concentration, in ppm.

2.2.3.11 The 95th percentile value of hourly NO_X pollutant concentration, in ppm.

2.2.3.12 The maximum value of hourly NO_X pollutant concentration, in ppm.

2.2.4 * * *

2.2.5 When a bias adjustment is necessary for the flow monitor or the NO_X continuous emission monitoring system (or the NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71), apply the adjustment factor to all monitor or continuous emission monitoring system data values placed in the load ranges.

2.2.6 Use the calculated monitor or monitoring system data averages, maximum values, and percentile values to substitute for missing flow rate and NO_X emission rate data (and where applicable, NO_X concentration data) according to the procedures in subpart D of this part.

* * * * *

21. Section 2 of appendix D to part 75 is amended by revising the introductory text of section 2.1.2 to read as follows:

APPENDIX D TO PART 75—OPTIONAL SO_2 EMISSIONS DATA PROTOCOL FOR GAS-FIRED AND OIL-FIRED UNITS

* * * * *

2.1.2 Install and use fuel flowmeters meeting the requirements of this appendix in a pipe going to each unit, or install and use a fuel flowmeter in a common pipe header (i.e., a pipe carrying fuel for multiple units). However, the use of a fuel flowmeter in a common pipe header and the provisions of sections 2.1.2.1 and 2.1.2.2 of this appendix are not applicable to any unit that is using the provisions of subpart H of this part to monitor, record, and report NO_X mass emissions under a State or federal NO_X mass emission reduction program, except as provided in § 75.72(a) for units with a NO_X CEMS installed in a common stack or except as provided for units monitored with an excepted monitoring system under appendix E to this part. For all other units, if the fuel flowmeter is installed in a common pipe header, do one of the following:

* * * * *

22. Section 8 of appendix F to part 75 is added to read as follows:

APPENDIX F TO PART 75—CONVERSION PROCEDURES

* * * * *

8. Procedures for NO_X Mass Emissions

The owner or operator of a unit that is required to monitor, record, and report NO_X mass emissions under a State or federal NO_X mass emission reduction program must use the procedures in section 8.1 to account for hourly NO_X mass emissions, and the procedures in section 8.2 to account for quarterly, seasonal, and annual NO_X mass emissions to the extent that the provisions of subpart H of this part are adopted as requirements under such a program.

8.1 Use the following procedures to calculate hourly NO_X mass emissions in lbs for the hour using hourly NO_X emission rate and heat input.

8.1.1 If both NO_X emission rate and heat input are monitored at the same unit or stack level (e.g, the NO_X emission rate value and heat input value both represent all of the units exhausting to the common stack), use the following equation:

$$M_{(NO_X)_h} = E_{(NO_X)_h} HI_h t_h \qquad \text{(Eq. F-24)}$$

where:

$M_{(NOx)h}$ = NO_X mass emissions in lbs for the hour.

$E_{(NOx)h}$ = Hourly average NO_X emission rate for hour h, lb/mmBtu, from section 3 of this appendix, from method 19 of appendix A to part 60 of this chapter, or from section 3.3 of appendix E to this part. (Include bias-adjusted NO_X emission rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

HI_h = Hourly average heat input rate for hour h, mmBtu/hr. (Include bias-adjusted flow rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

t_h = Monitoring location operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). If the combined NO_X emission rate and heat input are monitored for all of the units in a common stack, the monitoring location operating time is equal to the total time when any of those units was exhausting through the common stack.

8.1.2 If NO_X emission rate is measured at a common stack and heat input is measured at the unit level, sum the hourly heat inputs at the unit level according to the following formula:

$$HI_{CS} = \frac{\sum_{u=1}^{p} HI_u t_u}{t_{CS}} \qquad \text{(Eq. F-25)}$$

where:

HI_{CS} = Hourly average heat input rate for hour h for the units at the common stack, mmBtu/hr.

t_{CS} = Common stack operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)(e.g., total time when any of the units which exhaust through the common stack are operating).

HI_u = Hourly average heat input rate for hour h for the unit, mmBtu/hr.

t_u = Unit operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

Use the hourly heat input rate at the common stack level and the hourly average NO_X emission rate at the common stack level and the procedures in section 8.1.1 of this appendix to determine the hourly NO_X mass emissions at the common stack.

8.1.3 If a unit has multiple ducts and NO_X emission rate is only measured at one duct, use the NO_X emission rate measured at the duct, the heat input measured for the unit, and the procedures in section 8.1.1 of this appendix to determine NO_X mass emissions.

8.1.4 If a unit has multiple ducts and NO_X emission rate is measured in each duct, heat input shall also be measured in each duct and the procedures in section 8.1.1 of this appendix shall be used to determine NO_X mass emissions.

8.2 If a unit calculates NO_X mass emissions using a NO_X concentration monitoring system and a flow monitoring system, calculate hourly NO_X mass rate during unit (or stack) operation, in lb/hr, using Equation F–1 or F–2 in this appendix (as applicable to the moisture basis of the monitors). When using Equation F–1 or F–2, replace ''SO_2'' with ''NO_X'' and replace the value of K with 1.194 x 10^{-7} (lb NO_X /scf)/ppm. (Include bias-adjusted flow rate or NO_X concentration values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

8.3 If a unit calculates NO_X mass emissions using a NO_X concentration monitoring system and a flow monitoring system, calculate NO_X mass emissions for the hour (lb) by multiplying the hourly NO_X mass emission rate during unit operation (lb/hr) by the unit operating time during the hour, as follows:

$$M_{(NO_X)_h} = E_h t_h \qquad \text{(Eq. F-26)}$$

Where:

$M_{(NOx)h}$ = NO_X mass emissions in lbs for the hour.

E_h = Hourly NO_X mass emission rate during unit (or stack) operation, lb/hr, from section 8.2 of this appendix.

t_h = Monitoring location operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). If the NO_X mass emission rate is monitored for all of the units in a common stack, the monitoring location operating time is equal to the total time when any of those units was exhausting through the common stack.

8.4 Use the following procedures to calculate quarterly, cumulative ozone season, and cumulative yearly NO_X mass emissions, in tons:

$$M_{(NO_X)_{\text{time period}}} = \frac{\sum_{h=1}^{p} M_{(NO_X)_h}}{2000} \qquad \text{(Eq. F-27)}$$

Where:

$M_{(NOx)\ \text{time period}}$ = NO_X mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).

$M_{(NOx)h}$ = NO_X mass emissions in lbs for the hour. p = The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

8.5 Specific provisions for monitoring NO_X mass emissions from common stacks. The owner or operator of a unit utilizing a common stack may account for NO_X mass emissions using either of the following methodologies, if the provisions of subpart H are adopted as requirements of a State or federal NO_X mass reduction program:

8.5.1 The owner or operator may determine both NO_X emission rate and heat input at the common stack and use the procedures in section 8.1.1 of this appendix to determine hourly NO_X mass emissions at the common stack.

8.5.2 The owner or operator may determine the NO_X emission rate at the common stack and the heat input at each of the units and use the procedures in section 8.1.2 of this appendix to determine the hourly NO_X mass emissions at each unit.

23. Part 96 is added to read as follows:

PART 96—NO_X Budget Trading Program for State Implementation Plans

Subpart A—NO_X Budget Trading Program General Provisions

Sec.

Subpart G—NO_X Allowance Transfers

Subpart H—Monitoring and Reporting

Subpart I—Individual Unit Opt-ins

Subpart J—Mobile and Area Sources [Reserved]

Authority: 42 U.S.C. 7401, 7403, 7410, and 7601

Subpart A—NO_X Budget Trading Program General Provisions

§ 96.1 Purpose.

This part establishes general provisions and the applicability, permitting, allowance, excess emissions, monitoring, and opt-in provisions for the NO_X Budget Trading Program for State implementation plans as a means of mitigating the interstate transport of ozone and nitrogen oxides, an ozone precursor. The owner or operator of a unit, or any other person, shall comply with requirements of this part as a matter of federal law only to the extent a State that has jurisdiction over the unit incorporates by reference provisions of this part, or otherwise adopts such requirements of this part, and requires compliance, the State submits to the Administrator a State implementation plan including such adoption and such compliance requirement, and the Administrator approves the portion of the State implementation plan including such adoption and such compliance requirement. To the extent a State adopts requirements of this part, including at a minimum the requirements of subpart A (except for § 96.4(b)), subparts B through D, subpart F (except for § 96.55(c)), and subparts G and H of this part, the State authorizes the Administrator to assist the State in implementing the NO_X Budget Trading Program by carrying out the functions set forth for the Administrator in such requirements.

§ 96.2 Definitions.

The terms used in this part shall have the meanings set forth in this section as follows:

Account certificate of representation means the completed and signed submission required by subpart B of this part for certifying the designation of a NO_X authorized account representative for a NO_X Budget source or a group of identified NO_X Budget sources who is authorized to represent the owners and operators of such source or sources and of the NO_X Budget units at such source or sources with regard to matters under the NO_X Budget Trading Program.

Account number means the identification number given by the Administrator to each NO_X Allowance Tracking System account.

Acid Rain emissions limitation means, as defined in § 72.2 of this chapter, a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program under title IV of the CAA.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Allocate or *allocation* means the determination by the permitting authority or the Administrator of the number of NO_X allowances to be initially credited to a NO_X Budget unit or an allocation set-aside.

Automated data acquisition and handling system or *DAHS* means that component of the CEMS, or other emissions monitoring system approved for use under subpart H of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by subpart H of this part.

Boiler means an enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

CAA means the CAA, 42 U.S.C. 7401, *et seq.*, as amended by Pub. L. No. 101–549 (November 15, 1990).

Combined cycle system means a system comprised of one or more combustion turbines, heat recovery steam generators, and steam turbines configured to improve overall efficiency of electricity generation or steam production.

Combustion turbine means an enclosed fossil or other fuel-fired device that is comprised of a compressor, a combustor, and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine.

Commence commercial operation means, with regard to a unit that serves a generator, to have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation. Except as provided in § 96.5, for a unit that is a NO_X Budget unit under § 96.4 on the date the unit commences commercial operation, such date shall remain the unit's date of commencement of commercial operation even if the unit is subsequently modified, reconstructed, or repowered. Except as provided in § 96.5 or subpart I of this part, for a unit that is not a NO_X Budget unit under § 96.4 on the date the unit commences commercial operation, the date the unit becomes a NO_X Budget unit under § 96.4 shall be the unit's date of commencement of commercial operation.

Commence operation means to have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber. Except as provided in § 96.5, for a unit that is a NO_X Budget unit under § 96.4 on the date of commencement of operation, such date shall remain the unit's date of commencement of operation even if the unit is subsequently modified, reconstructed, or repowered. Except as provided in § 96.5 or subpart I of this part, for a unit that is not a NO_X Budget unit under § 96.4 on the date of commencement of operation, the date the unit becomes a NO_X Budget unit under § 96.4 shall be the unit's date of commencement of operation.

Common stack means a single flue through which emissions from two or more units are exhausted.

Compliance account means a NO_X Allowance Tracking System account, established by the Administrator for a NO_X Budget unit under subpart F of this part, in which the NO_X allowance allocations for the unit are initially recorded and in which are held NO_X allowances available for use by the unit for a control period for the purpose of meeting the unit's NO_X Budget emissions limitation.

Compliance certification means a submission to the permitting authority or the Administrator, as appropriate, that is required under subpart D of this part to report a NO_X Budget source's or a NO_X Budget unit's compliance or noncompliance with this part and that is signed by the NO_X authorized account representative in accordance with subpart B of this part.

Continuous emission monitoring system or *CEMS* means the equipment required under subpart H of this part to sample, analyze, measure, and provide, by readings taken at least once every 15 minutes of the measured parameters, a permanent record of nitrogen oxides emissions, expressed in tons per hour for nitrogen oxides. The following systems are component parts included, consistent with part 75 of this chapter, in a continuous emission monitoring system:

(1) Flow monitor;

(2) Nitrogen oxides pollutant concentration monitors;

(3) Diluent gas monitor (oxygen or carbon dioxide) when such monitoring is required by subpart H of this part;

(4) A continuous moisture monitor when such monitoring is required by subpart H of this part; and

(5) An automated data acquisition and handling system.

Control period means the period beginning May 1 of a year and ending on September 30 of the same year, inclusive.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the NO_X authorized account representative and as determined by the Administrator in accordance with subpart H of this part.

Energy Information Administration means the Energy Information Administration of the United States Department of Energy.

Excess emissions means any tonnage of nitrogen oxides emitted by a NO_X Budget unit during a control period that exceeds the NO_X Budget emissions limitation for the unit.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil fuel-fired means, with regard to a unit:

(1) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel actually combusted comprises more than 50 percent of the annual heat input on a Btu basis during any year starting in 1995 or, if a unit had no heat input starting in 1995, during the last year of operation of the unit prior to 1995; or

(2) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel is projected to comprise more than 50 percent of the annual heat input on a Btu basis during any year; provided that the unit shall be "fossil fuel-fired" as of the date, during such year, on which the unit begins combusting fossil fuel.

General account means a NO_X Allowance Tracking System account, established under subpart F of this part, that is not a compliance account or an overdraft account.

Generator means a device that produces electricity.

Heat input means the product (in mmBtu/time) of the gross calorific value of the fuel (in Btu/lb) and the fuel feed rate into a combustion device (in mass of fuel/time), as measured, recorded, and reported to the Administrator by the NO_X authorized account representative and as determined by the Administrator in accordance with subpart H of this part, and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy from any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period equal to or greater than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means the ability of a unit to combust a stated maximum amount of fuel per hour on a steady state basis, as determined by the physical design and physical characteristics of the unit.

Maximum potential hourly heat input means an hourly heat input used for reporting purposes when a unit lacks certified monitors to report heat input. If the unit intends to use appendix D of part 75 of this chapter to report heat input, this value should be calculated, in accordance with part 75 of this chapter, using the maximum fuel flow rate and the maximum gross calorific value. If the unit intends to use a flow monitor and a diluent gas monitor, this value should be reported, in accordance with part 75 of this chapter, using the maximum potential flowrate and either the maximum carbon dioxide concentration (in percent CO_2) or the minimum oxygen concentration (in percent O_2).

Maximum potential NO_X emission rate means the emission rate of nitrogen oxides (in lb/mmBtu) calculated in accordance with section 3 of appendix F of part 75 of this chapter, using the maximum potential nitrogen oxides concentration as defined in section 2 of appendix A of part 75 of this chapter, and either the maximum oxygen concentration (in percent O_2) or the minimum carbon dioxide concentration (in percent CO_2), under all operating conditions of the unit except for unit start up, shutdown, and upsets.

Maximum rated hourly heat input means a unit-specific maximum hourly heat input (mmBtu) which is the higher of the manufacturer's maximum rated hourly heat input or the highest observed hourly heat input.

Monitoring system means any monitoring system that meets the requirements of subpart H of this part, including a continuous emissions monitoring system, an excepted monitoring system, or an alternative monitoring system.

Most stringent State or Federal NO_X emissions limitation means, with regard to a NO_X Budget opt-in source, the lowest NO_X emissions limitation (in terms of lb/mmBtu) that is applicable to the unit under State or Federal law, regardless of the averaging period to which the emissions limitation applies.

Nameplate capacity means the maximum electrical generating output (in MWe) that a generator can sustain over a specified period of time when not restricted by seasonal or other deratings as measured in accordance with the United States Department of Energy standards.

Non-title V permit means a federally enforceable permit administered by the permitting authority pursuant to the CAA and regulatory authority under the CAA, other than title V of the CAA and part 70 or 71 of this chapter.

NO_X allowance means an authorization by the permitting authority or the Administrator under the NO_X Budget Trading Program to emit up to one ton of nitrogen oxides during the control period of the specified year or of any year thereafter.

NO_X allowance deduction or *deduct NO_X allowances* means the permanent withdrawal of NO_X allowances by the

Administrator from a NO_X Allowance Tracking System compliance account or overdraft account to account for the number of tons of NO_X emissions from a NO_X Budget unit for a control period, determined in accordance with subpart H of this part, or for any other allowance surrender obligation under this part.

NO_X allowances held or *hold NO_X allowances* means the NO_X allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with subparts F and G of this part, in a NO_X Allowance Tracking System account.

NO_X Allowance Tracking System means the system by which the Administrator records allocations, deductions, and transfers of NO_X allowances under the NO_X Budget Trading Program.

NO_X Allowance Tracking System account means an account in the NO_X Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of NO_X allowances.

NO_X allowance transfer deadline means midnight of November 30 or, if November 30 is not a business day, midnight of the first business day thereafter and is the deadline by which NO_X allowances may be submitted for recordation in a NO_X Budget unit's compliance account, or the overdraft account of the source where the unit is located, in order to meet the unit's NO_X Budget emissions limitation for the control period immediately preceding such deadline.

NO_X authorized account representative means, for a NO_X Budget source or NO_X Budget unit at the source, the natural person who is authorized by the owners and operators of the source and all NO_X Budget units at the source, in accordance with subpart B of this part, to represent and legally bind each owner and operator in matters pertaining to the NO_X Budget Trading Program or, for a general account, the natural person who is authorized, in accordance with subpart F of this part, to transfer or otherwise dispose of NO_X allowances held in the general account.

NO_X Budget emissions limitation means, for a NO_X Budget unit, the tonnage equivalent of the NO_X allowances available for compliance deduction for the unit and for a control period under § 96.54(a) and (b), adjusted by any deductions of such NO_X allowances to account for actual utilization under § 96.42(e) for the control period or to account for excess emissions for a prior control period under § 96.54(d) or to account for withdrawal from the NO_X Budget Program, or for a change in regulatory status, for a NO_X Budget opt-in source under § 96.86 or § 96.87.

NO_X Budget opt-in permit means a NO_X Budget permit covering a NO_X Budget opt-in source.

NO_X Budget opt-in source means a unit that has been elected to become a NO_X Budget unit under the NO_X Budget Trading Program and whose NO_X Budget opt-in permit has been issued and is in effect under subpart I of this part.

NO_X Budget permit means the legally binding and federally enforceable written document, or portion of such document, issued by the permitting authority under this part, including any permit revisions, specifying the NO_X Budget Trading Program requirements applicable to a NO_X Budget source, to each NO_X Budget unit at the NO_X Budget source, and to the owners and operators and the NO_X authorized account representative of the NO_X Budget source and each NO_X Budget unit.

NO_X Budget source means a source that includes one or more NO_X Budget units.

NO_X Budget Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program established in accordance with this part and pursuant to § 51.121 of this chapter, as a means of mitigating the interstate transport of ozone and nitrogen oxides, an ozone precursor.

NO_X Budget unit means a unit that is subject to the NO_X Budget Trading Program emissions limitation under § 96.4 or § 96.80.

Operating means, with regard to a unit under §§ 96.22(d)(2) and 96.80, having documented heat input for more than 876 hours in the 6 months immediately preceding the submission of an application for an initial NO_X Budget permit under § 96.83(a).

Operator means any person who operates, controls, or supervises a NO_X Budget unit, a NO_X Budget source, or unit for which an application for a NO_X Budget opt-in permit under § 96.83 is submitted and not denied or withdrawn and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Opt-in means to be elected to become a NO_X Budget unit under the NO_X Budget Trading Program through a final, effective NO_X Budget opt-in permit under subpart I of this part.

Overdraft account means the NO_X Allowance Tracking System account, established by the Administrator under subpart F of this part, for each NO_X Budget source where there are two or more NO_X Budget units.

Owner means any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a NO_X Budget unit or in a unit for which an application for a NO_X Budget opt-in permit under § 96.83 is submitted and not denied or withdrawn; or

(2) Any holder of a leasehold interest in a NO_X Budget unit or in a unit for which an application for a NO_X Budget opt-in permit under § 96.83 is submitted and not denied or withdrawn; or

(3) Any purchaser of power from a NO_X Budget unit or from a unit for which an application for a NO_X Budget opt-in permit under § 96.83 is submitted and not denied or withdrawn under a life-of-the-unit, firm power contractual arrangement. However, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the NO_X Budget unit or the unit for which an application for a NO_X Budget opt-in permit under § 96.83 is submitted and not denied or withdrawn; or

(4) With respect to any general account, any person who has an ownership interest with respect to the NO_X allowances held in the general account and who is subject to the binding agreement for the NO_X authorized account representative to represent that person's ownership interest with respect to NO_X allowances.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the NO_X Budget Trading Program in accordance with subpart C of this part.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in writing or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to NO_X allowances, the movement of NO_X allowances by the Administrator from one NO_X Allowance Tracking System account to another, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in appendix A of part 60 of this chapter.

Serial number means, when referring to NO_X allowances, the unique identification number assigned to each NO_X allowance by the Administrator, under § 96.53(c).

Source means any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any regulated air pollutant under the CAA. For purposes of section 502(c) of the CAA, a ''source,'' including a ''source'' with multiple units, shall be considered a single ''facility.''

State means one of the 48 contiguous States and the District of Columbia specified in § 51.121 of this chapter, or any non-federal authority in or including such States or the District of Columbia (including local agencies, and Statewide agencies) or any eligible Indian tribe in an area of such State or the District of Columbia, that adopts a NO_X Budget Trading Program pursuant to § 51.121 of this chapter. To the extent a State incorporates by reference the provisions of this part, the term ''State'' shall mean the incorporating State. The term ''State'' shall have its conventional meaning where such meaning is clear from the context.

State trading program budget means the total number of NO_X tons apportioned to all NO_X Budget units in a given State, in accordance with the NO_X Budget Trading Program, for use in a given control period.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery. Compliance with any ''submission,'' ''service,'' or ''mailing'' deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Title V operating permit means a permit issued under title V of the CAA and part 70 or part 71 of this chapter.

Title V operating permit regulations means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the CAA and part 70 or 71 of this chapter.

Ton or tonnage means any ''short ton'' (i.e., 2,000 pounds). For the purpose of determining compliance with the NO_X Budget emissions limitation, total tons for a control period shall be calculated as the sum of all recorded hourly emissions (or the tonnage equivalent of the recorded hourly emissions rates) in accordance with subpart H of this part, with any remaining fraction of a ton equal to or greater than 0.50 ton deemed to equal one ton and any fraction of a ton less than 0.50 ton deemed to equal zero tons.

Unit means a fossil fuel-fired stationary boiler, combustion turbine, or combined cycle system.

Unit load means the total (i.e., gross) output of a unit in any control period (or other specified time period) produced by combusting a given heat input of fuel, expressed in terms of:

(1) The total electrical generation (MWe) produced by the unit, including generation for use within the plant; or

(2) In the case of a unit that uses heat input for purposes other than electrical generation, the total steam pressure (psia) produced by the unit, including steam for use by the unit.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or *hour of unit operation* means any hour (or fraction of an hour) during which a unit combusts any fuel.

Utilization means the heat input (expressed in mmBtu/time) for a unit. The unit's total heat input for the control period in each year will be determined in accordance with part 75 of this chapter if the NO_X Budget unit was otherwise subject to the requirements of part 75 of this chapter for the year, or will be based on the best available data reported to the Administrator for the unit if the unit was not otherwise subject to the requirements of part 75 of this chapter for the year.

§ 96.3 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this part are defined as follows:

Btu—British thermal unit.
hr—hour.
Kwh—kilowatt hour.
lb—pounds.
mmBtu—million Btu.
MWe—megawatt electrical.
ton—2000 pounds.
CO_2—carbon dioxide.
NO_X—nitrogen oxides.
O_2—oxygen.

§ 96.4 Applicability.

(a) The following units in a State shall be NO_X Budget units, and any source that includes one or more such units shall be a NO_X Budget source, subject to the requirements of this part:

(1) Any unit that, any time on or after January 1, 1995, serves a generator with a nameplate capacity greater than 25 MWe and sells any amount of electricity; or

(2) Any unit that is not a unit under paragraph (a) of this section and that has a maximum design heat input greater than 250 mmBtu/hr.

(b) Notwithstanding paragraph (a) of this section, a unit under paragraph (a) of this section shall be subject only to the requirements of this paragraph (b) if the unit has a federally enforceable permit that meets the requirements of paragraph (b)(1) of this section and restricts the unit to burning only natural gas or fuel oil during a control period in 2003 or later and each control period thereafter and restricts the unit's operating hours during each such control period to the number of hours (determined in accordance with paragraph (b)(1)(ii) and (iii) of this section) that limits the unit's potential NO_X mass emissions for the control period to 25 tons or less. Notwithstanding paragraph (a) of this section, starting with the effective date of such federally enforceable permit, the unit shall not be a NO_X Budget unit.

(1) For each control period under paragraph (b) of this section, the federally enforceable permit must:

(i) Restrict the unit to burning only natural gas or fuel oil.

(ii) Restrict the unit's operating hours to the number calculated by dividing 25 tons of potential NO_X mass emissions by the unit's maximum potential hourly NO_X mass emissions.

(iii) Require that the unit's potential NO_X mass emissions shall be calculated as follows:

(A) Select the default NO_X emission rate in Table 2 of § 75.19 of this chapter that would otherwise be applicable assuming that the unit burns only the type of fuel (i.e., only natural gas or only fuel oil) that has the highest default NO_X emission factor of any type of fuel that the unit is allowed to burn under the fuel use restriction in paragraph (b)(1)(i) of this section; and

(B) Multiply the default NO_X emission rate under paragraph (b)(1)(iii)(A) of this section by the unit's maximum rated hourly heat input. The owner or operator of the unit may petition the permitting authority to use a lower value for the unit's maximum rated hourly heat input than the value as defined under § 96.2. The permitting authority may approve such lower value if the owner or operator demonstrates that the maximum hourly heat input specified by the manufacturer or the highest observed hourly heat input, or both, are not representative, and that such lower value is representative, of the unit's current capabilities because modifications have been made to the unit, limiting its capacity permanently.

(iv) Require that the owner or operator of the unit shall retain at the source that includes the unit, for 5 years, records demonstrating that the operating hours restriction, the fuel use restriction, and the other requirements of the permit related to these restrictions were met.

(v) Require that the owner or operator of the unit shall report the unit's hours of operation (treating any partial hour of operation as a whole hour of operation) during each control period to the permitting authority by November 1 of each year for which the unit is subject to the federally enforceable permit.

(2) The permitting authority that issues the federally enforceable permit with the fuel use restriction under paragraph (b)(1)(i) and the operating hours restriction under paragraphs (b)(1)(ii) and (iii) of this section will notify the Administrator in writing of each unit under paragraph (a) of this section whose federally enforceable permit issued by the permitting authority includes such restrictions. The permitting authority will also notify the Administrator in writing of each unit under paragraph (a) of this section whose federally enforceable permit issued by the permitting authority is revised to remove any such restriction, whose federally enforceable permit issued by the permitting authority includes any such restriction that is no longer applicable, or which does not comply with any such restriction.

(3) If, for any control period under paragraph (b) of this section, the fuel use restriction under paragraph (b)(1)(i) of this section or the operating hours restriction under paragraphs (b)(1)(ii) and (iii) of this section is removed from the unit's federally enforceable permit or otherwise becomes no longer applicable or if, for any such control period, the unit does not comply with the fuel use restriction under paragraph (b)(1)(i) of this section or the operating hours restriction under paragraphs (b)(1)(ii) and (iii) of this section, the unit shall be a NO_X Budget unit, subject to the requirements of this part. Such unit shall be treated as commencing operation and, for a unit under paragraph (a)(1) of this section, commencing commercial operation on September 30 of the control period for which the fuel use restriction or the operating hours restriction is no longer applicable or during which the unit does not comply with the fuel use restriction or the operating hours restriction.

§ 96.5 Retired unit exemption.

(a) This section applies to any NO_X Budget unit, other than a NO_X Budget opt-in source, that is permanently retired.

(b)(1) Any NO_X Budget unit, other than a NO_X Budget opt-in source, that is permanently retired shall be exempt from the NO_X Budget Trading Program, except for the provisions of this section, §§ 96.2, 96.3, 96.4, 96.7 and subparts E, F, and G of this part.

(2) The exemption under paragraph (b)(1) of this section shall become effective the day on which the unit is permanently retired. Within 30 days of permanent retirement, the NO_X authorized account representative (authorized in accordance with subpart B of this part) shall submit a statement to the permitting authority otherwise responsible for administering any NO_X Budget permit for the unit. A copy of the statement shall be submitted to the Administrator. The statement shall state (in a format prescribed by the permitting authority) that the unit is permanently retired and will comply with the requirements of paragraph (c) of this section.

(3) After receipt of the notice under paragraph (b)(2) of this section, the permitting authority will amend any permit covering the source at which the unit is located to add the provisions and requirements of the exemption under paragraphs (b)(1) and (c) of this section.

(c) *Special provisions.* (1) A unit exempt under this section shall not emit any nitrogen oxides, starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with subpart E of this part.

(2)(i) A unit exempt under this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the NO_X authorized account representative of the source submits a complete NO_X Budget permit application under § 96.22 for the unit not less than 18 months (or such lesser time provided under the permitting authority's title V operating permits regulations for final action on a permit application) prior to the later of May 1, 2003 or the date on which the unit is to first resume operation.

(ii) A unit exempt under this section and located at a source that is required, or but for this exemption would be required, to have a non-title V permit shall not resume operation unless the NO_X authorized account representative of the source submits a complete NO_X Budget permit application under § 96.22 for the unit not less than 18 months (or such lesser time provided under the permitting authority's non-title V permits regulations for final action on a permit application) prior to the later of May 1, 2003 or the date on which the unit is to first resume operation.

(3) The owners and operators and, to the extent applicable, the NO_X authorized account representative of a unit exempt under this section shall comply with the requirements of the NO_X Budget Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit that is exempt under this section is not eligible to be a NO_X Budget opt-in source under subpart I of this part.

(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under this section shall retain at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(6) *Loss of exemption.* (i) On the earlier of the following dates, a unit exempt under paragraph (b) of this section shall lose its exemption:

(A) The date on which the NO_X authorized account representative submits a NO_X Budget permit application under paragraph (c)(2) of this section; or

(B) The date on which the NO_X authorized account representative is required under paragraph (c)(2) of this section to submit a NO_X Budget permit application.

(ii) For the purpose of applying monitoring requirements under subpart H of this part, a unit that loses its exemption under this section shall be treated as a unit that commences operation or commercial operation on the first date on which the unit resumes operation.

§ 96.6 Standard requirements.

(a) *Permit Requirements.* (1) The NO_X authorized account representative of each NO_X Budget source required to have a federally enforceable permit and each NO_X Budget unit required to have a federally enforceable permit at the source shall:

(i) Submit to the permitting authority a complete NO_X Budget permit application under § 96.22 in accordance with the deadlines specified in § 96.21(b) and (c);

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a NO_X Budget permit application and issue or deny a NO_X Budget permit.

(2) The owners and operators of each NO_X Budget source required to have a federally enforceable permit and each NO_X Budget unit required to have a federally enforceable permit at the source shall have a NO_X Budget permit issued by the permitting authority and operate the unit in compliance with such NO_X Budget permit.

(3) The owners and operators of a NO_X Budget source that is not otherwise required to have a federally enforceable permit are not required to submit a NO_X Budget permit application, and to have a NO_X Budget permit, under subpart C of this part for such NO_X Budget source.

(b) *Monitoring requirements.* (1) The owners and operators and, to the extent applicable, the NO_X authorized account representative of each NO_X Budget source and each NO_X Budget unit at the source shall comply with the monitoring requirements of subpart H of this part.

(2) The emissions measurements recorded and reported in accordance with subpart H of this part shall be used to determine compliance by the unit with the NO_X Budget emissions limitation under paragraph (c) of this section.

(c) *Nitrogen oxides requirements.* (1) The owners and operators of each NO_X Budget source and each NO_X Budget unit at the source shall hold NO_X allowances available for compliance deductions under § 96.54, as of the NO_X allowance transfer deadline, in the unit's compliance account and the source's overdraft account in an amount not less than the total NO_X emissions for the control period from the unit, as determined in accordance with subpart H of this part, plus any amount necessary to account for actual utilization under § 96.42(e) for the control period.

(2) Each ton of nitrogen oxides emitted in excess of the NO_X Budget emissions limitation shall constitute a separate violation of this part, the CAA, and applicable State law.

(3) A NO_X Budget unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later of May 1, 2003 or the date on which the unit commences operation.

(4) NO_X allowances shall be held in, deducted from, or transferred among NO_X Allowance Tracking System accounts in accordance with subparts E, F, G, and I of this part.

(5) A NO_X allowance shall not be deducted, in order to comply with the requirements under paragraph (c)(1) of this section, for a control period in a year prior to the year for which the NO_X allowance was allocated.

(6) A NO_X allowance allocated by the permitting authority or the Administrator under the NO_X Budget Trading Program is a limited authorization to emit one ton of nitrogen oxides in accordance with the NO_X Budget Trading Program. No provision of the NO_X Budget Trading Program, the NO_X Budget permit application, the NO_X Budget permit, or an exemption under § 96.5 and no provision of law shall be construed to limit the authority of the United States or the State to terminate or limit such authorization.

(7) A NO_X allowance allocated by the permitting authority or the Administrator under the NO_X Budget Trading Program does not constitute a property right.

(8) Upon recordation by the Administrator under subpart F, G, or I of this part, every allocation, transfer, or deduction of a NO_X allowance to or from a NO_X Budget unit's compliance account or the overdraft account of the source where the unit is located is deemed to amend automatically, and become a part of, any NO_X Budget permit of the NO_X Budget unit by operation of law without any further review.

(d) *Excess emissions requirements.* (1) The owners and operators of a NO_X Budget unit that has excess emissions in any control period shall:

(i) Surrender the NO_X allowances required for deduction under § 96.54(d)(1); and

(ii) Pay any fine, penalty, or assessment or comply with any other remedy imposed under § 96.54(d)(3).

(e) Recordkeeping and Reporting requirements.

(1) Unless otherwise provided, the owners and operators of the NO_X Budget source and each NO_X Budget unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The account certificate of representation for the NO_X authorized account representative for the source and each NO_X Budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with § 96.13; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new account certificate of representation changing the NO_X authorized account representative.

(ii) All emissions monitoring information, in accordance with subpart H of this part; provided that to the extent that subpart H of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the NO_X Budget Trading Program.

(iv) Copies of all documents used to complete a NO_X Budget permit application and any other submission under the NO_X Budget Trading Program or to demonstrate compliance with the requirements of the NO_X Budget Trading Program.

(2) The NO_X authorized account representative of a NO_X Budget source and each NO_X Budget unit at the source shall submit the reports and compliance certifications required under the NO_X Budget Trading Program, including those under subparts D, H, or I of this part.

(f) *Liability.* (1) Any person who knowingly violates any requirement or prohibition of the NO_X Budget Trading Program, a NO_X Budget permit, or an exemption under § 96.5 shall be subject to enforcement pursuant to applicable State or Federal law.

(2) Any person who knowingly makes a false material statement in any record, submission, or report under the NO_X Budget Trading Program shall be subject to criminal enforcement pursuant to the applicable State or Federal law.

(3) No permit revision shall excuse any violation of the requirements of the NO_X Budget Trading Program that occurs prior to the date that the revision takes effect.

(4) Each NO_X Budget source and each NO_X Budget unit shall meet the requirements of the NO_X Budget Trading Program.

(5) Any provision of the NO_X Budget Trading Program that applies to a NO_X Budget source (including a provision applicable to the NO_X authorized account representative of a NO_X Budget source) shall also apply to the owners and operators of such source and of the NO_X Budget units at the source.

(6) Any provision of the NO_X Budget Trading Program that applies to a NO_X Budget unit (including a provision applicable to the NO_X authorized

account representative of a NO_X budget unit) shall also apply to the owners and operators of such unit. Except with regard to the requirements applicable to units with a common stack under subpart H of this part, the owners and operators and the NO_X authorized account representative of one NO_X Budget unit shall not be liable for any violation by any other NO_X Budget unit of which they are not owners or operators or the NO_X authorized account representative and that is located at a source of which they are not owners or operators or the NO_X authorized account representative.

(g) *Effect on other authorities.* No provision of the NO_X Budget Trading Program, a NO_X Budget permit application, a NO_X Budget permit, or an exemption under § 96.5 shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the NO_X authorized account representative of a NO_X Budget source or NO_X Budget unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the CAA.

§ 96.7 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the NO_X Budget Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the NO_X Budget Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the NO_X Budget Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

Subpart B—NO_X Authorized Account Representative for NO_X Budget Sources

§ 96.10 Authorization and responsibilities of the NO_X authorized account representative.

(a) Except as provided under § 96.11, each NO_X Budget source, including all NO_X Budget units at the source, shall have one and only one NO_X authorized account representative, with regard to all matters under the NO_X Budget Trading Program concerning the source or any NO_X Budget unit at the source.

(b) The NO_X authorized account representative of the NO_X Budget source shall be selected by an agreement binding on the owners and operators of the source and all NO_X Budget units at the source.

(c) Upon receipt by the Administrator of a complete account certificate of representation under § 96.13, the NO_X authorized account representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the NO_X Budget source represented and each NO_X Budget unit at the source in all matters pertaining to the NO_X Budget Trading Program, not withstanding any agreement between the NO_X authorized account representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the NO_X authorized account representative by the permitting authority, the Administrator, or a court regarding the source or unit.

(d) No NO_X Budget permit shall be issued, and no NO_X Allowance Tracking System account shall be established for a NO_X Budget unit at a source, until the Administrator has received a complete account certificate of representation under § 96.13 for a NO_X authorized account representative of the source and the NO_X Budget units at the source.

(e)(1) Each submission under the NO_X Budget Trading Program shall be submitted, signed, and certified by the NO_X authorized account representative for each NO_X Budget source on behalf of which the submission is made. Each such submission shall include the following certification statement by the NO_X authorized account representative: ''I am authorized to make this submission on behalf of the owners and operators of the NO_X Budget sources or NO_X Budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) The permitting authority and the Administrator will accept or act on a submission made on behalf of owner or operators of a NO_X Budget source or a NO_X Budget unit only if the submission has been made, signed, and certified in accordance with paragraph (e)(1) of this section.

§ 96.11 Alternate NO_X authorized account representative.

(a) An account certificate of representation may designate one and only one alternate NO_X authorized account representative who may act on behalf of the NO_X authorized account representative. The agreement by which the alternate NO_X authorized account representative is selected shall include a procedure for authorizing the alternate NO_X authorized account representative to act in lieu of the NO_X authorized account representative.

(b) Upon receipt by the Administrator of a complete account certificate of representation under § 96.13, any representation, action, inaction, or submission by the alternate NO_X authorized account representative shall be deemed to be a representation, action, inaction, or submission by the NO_X authorized account representative.

(c) Except in this section and §§ 96.10(a), 96.12, 96.13, and 96.51, whenever the term ''NO_X authorized account representative'' is used in this part, the term shall be construed to include the alternate NO_X authorized account representative.

§ 96.12 Changing the NO_X authorized account representative and the alternate NO_X authorized account representative; changes in the owners and operators.

(a) *Changing the NO_X authorized account representative.* The NO_X authorized account representative may be changed at any time upon receipt by the Administrator of a superseding complete account certificate of representation under § 96.13. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous NO_X authorized account representative prior to the time and date when the Administrator receives the superseding account certificate of representation shall be binding on the new NO_X authorized account representative and the owners and operators of the NO_X Budget source and the NO_X Budget units at the source.

(b) Changing the alternate NO_X authorized account representative. The alternate NO_X authorized account representative may be changed at any time upon receipt by the Administrator of a superseding complete account certificate of representation under § 96.13. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate NO_X authorized account representative prior to the time and date when the Administrator receives the superseding account certificate of representation shall be binding on the new alternate NO_X authorized account representative and the owners and operators of the NO_X Budget source and the NO_X Budget units at the source.

(c) *Changes in the owners and operators.* (1) In the event a new owner or operator of a NO_X Budget source or a NO_X Budget unit is not included in the list of owners and operators submitted in the account certificate of representation, such new owner or operator shall be deemed to be subject to and bound by the account certificate of representation, the representations, actions, inactions, and submissions of the NO_X authorized account representative and any alternate NO_X authorized account representative of the source or unit, and the decisions, orders, actions, and inactions of the permitting authority or the Administrator, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a NO_X Budget source or a NO_X Budget unit, including the addition of a new owner or operator, the NO_X authorized account representative or alternate NO_X authorized account representative shall submit a revision to the account certificate of representation amending the list of owners and operators to include the change.

§ 96.13 Account certificate of representation.

(a) A complete account certificate of representation for a NO_X authorized account representative or an alternate NO_X authorized account representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the NO_X Budget source and each NO_X Budget unit at the source for which the account certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the NO_X authorized account representative and any alternate NO_X authorized account representative.

(3) A list of the owners and operators of the NO_X Budget source and of each NO_X Budget unit at the source.

(4) The following certification statement by the NO_X authorized account representative and any alternate NO_X authorized account representative: ''I certify that I was selected as the NO_X authorized account representative or alternate NO_X authorized account representative, as applicable, by an agreement binding on the owners and operators of the NO_X Budget source and each NO_X Budget unit at the source. I certify that I have all the necessary authority to carry out my duties and responsibilities under the NO_X Budget Trading Program on behalf of the owners and operators of the NO_X Budget source and of each NO_X Budget unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the permitting authority, the Administrator, or a court regarding the source or unit.''

(5) The signature of the NO_X authorized account representative and any alternate NO_X authorized account representative and the dates signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the account certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 96.14 Objections concerning the NO_X authorized account representative.

(a) Once a complete account certificate of representation under § 96.13 has been submitted and received, the permitting authority and the Administrator will rely on the account certificate of representation unless and until a superseding complete account certificate of representation under § 96.13 is received by the Administrator.

(b) Except as provided in § 96.12(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission of the NO_X authorized account representative shall affect any representation, action, inaction, or submission of the NO_X authorized account representative or the finality of any decision or order by the permitting authority or the Administrator under the NO_X Budget Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any NO_X authorized account representative, including private legal disputes concerning the proceeds of NO_X allowance transfers.

Subpart C—Permits

§ 96.20 General NO_X Budget trading program permit requirements.

(a) For each NO_X Budget source required to have a federally enforceable permit, such permit shall include a NO_X Budget permit administered by the permitting authority.

(1) For NO_X Budget sources required to have a title V operating permit, the NO_X Budget portion of the title V permit shall be administered in accordance with the permitting authority's title V operating permits regulations promulgated under part 70 or 71 of this chapter, except as provided otherwise by this subpart or subpart I of this part. The applicable provisions of such title V operating permits regulations shall include, but are not limited to, those provisions addressing operating permit applications, operating permit application shield, operating permit duration, operating permit shield, operating permit issuance, operating permit revision and reopening, public participation, State review, and review by the Administrator.

(2) For NO_X Budget sources required to have a non-title V permit, the NO_X Budget portion of the non-title V permit shall be administered in accordance with the permitting authority's regulations promulgated to administer non-title V permits, except as provided otherwise by this subpart or subpart I of this part. The applicable provisions of such non-title V permits regulations may include, but are not limited to, provisions addressing permit applications, permit application shield, permit duration, permit shield, permit issuance, permit revision and reopening, public participation, State review, and review by the Administrator.

(b) Each NO_X Budget permit (including a draft or proposed NO_X Budget permit, if applicable) shall contain all applicable NO_X Budget Trading Program requirements and shall be a complete and segregable portion of the permit under paragraph (a) of this section.

§ 96.21 Submission of NO_X Budget permit applications.

(a) *Duty to apply.* The NO_X authorized account representative of any NO_X Budget source required to have a federally enforceable permit shall submit to the permitting authority a complete NO_X Budget permit application under § 96.22 by the applicable deadline in paragraph (b) of this section.

(b)(1) For NO_X Budget sources required to have a title V operating permit:

(i) For any source, with one or more NO_X Budget units under § 96.4 that commence operation before January 1, 2000, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 covering such NO_X Budget units to the permitting authority at least 18 months (or such lesser time provided under the permitting authority's title V operating permits regulations for final action on a permit application) before May 1, 2003.

(ii) For any source, with any NO_X Budget unit under § 96.4 that commences operation on or after January 1, 2000, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 covering such NO_X Budget unit to the permitting authority at least 18 months (or such lesser time provided under the permitting authority's title V operating permits regulations for final action on a permit application) before the later of May 1, 2003 or the date on which the NO_X Budget unit commences operation.

(2) For NO_X Budget sources required to have a non-title V permit:

(i) For any source, with one or more NO_X Budget units under § 96.4 that commence operation before January 1, 2000, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 covering such NO_X Budget units to the permitting authority at least 18 months (or such lesser time provided under the permitting authority's non-title V permits regulations for final action on a permit application) before May 1, 2003.

(ii) For any source, with any NO_X Budget unit under § 96.4 that commences operation on or after January 1, 2000, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 covering such NO_X Budget unit to the permitting authority at least 18 months (or such lesser time provided under the permitting authority's non-title V permits regulations for final action on a permit application) before the later of May 1, 2003 or the date on which the NO_X Budget unit commences operation.

(c) *Duty to reapply.* (1) For a NO_X Budget source required to have a title V operating permit, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 for the NO_X Budget source covering the NO_X Budget units at the source in accordance with the permitting authority's title V operating permits regulations addressing operating permit renewal.

(2) For a NO_X Budget source required to have a non-title V permit, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 for the NO_X Budget source covering the NO_X Budget units at the source in accordance with the permitting authority's non-title V permits regulations addressing permit renewal.

§ 96.22 Information requirements for NO_X Budget permit applications.

A complete NO_X Budget permit application shall include the following elements concerning the NO_X Budget source for which the application is submitted, in a format prescribed by the permitting authority:

(a) Identification of the NO_X Budget source, including plant name and the ORIS (Office of Regulatory Information Systems) or facility code assigned to the source by the Energy Information Administration, if applicable;

(b) Identification of each NO_X Budget unit at the NO_X Budget source and whether it is a NO_X Budget unit under § 96.4 or under subpart I of this part;

(c) The standard requirements under § 96.6; and

(d) For each NO_X Budget opt-in unit at the NO_X Budget source, the following certification statements by the NO_X authorized account representative:

(1) ''I certify that each unit for which this permit application is submitted under subpart I of this part is not a NO_X Budget unit under 40 CFR 96.4 and is not covered by a retired unit exemption under 40 CFR 96.5 that is in effect.''

(2) If the application is for an initial NO_X Budget opt-in permit, ''I certify that each unit for which this permit application is submitted under subpart I is currently operating, as that term is defined under 40 CFR 96.2.''

§ 96.23 NO_X Budget permit contents.

(a) Each NO_X Budget permit (including any draft or proposed NO_X Budget permit, if applicable) will contain, in a format prescribed by the permitting authority, all elements required for a complete NO_X Budget permit application under § 96.22 as approved or adjusted by the permitting authority.

(b) Each NO_X Budget permit is deemed to incorporate automatically the definitions of terms under § 96.2 and, upon recordation by the Administrator under subparts F, G, or I of this part, every allocation, transfer, or deduction of a NO_X allowance to or from the compliance accounts of the NO_X Budget units covered by the permit or the overdraft account of the NO_X Budget source covered by the permit.

§ 96.24 Effective date of initial NO_X Budget permit.

The initial NO_X Budget permit covering a NO_X Budget unit for which a complete NO_X Budget permit application is timely submitted under § 96.21(b) shall become effective by the later of:

(a) May 1, 2003;

(b) May 1 of the year in which the NO_X Budget unit commences operation, if the unit commences operation on or before May 1 of that year;

(c) The date on which the NO_X Budget unit commences operation, if the unit commences operation during a control period; or

(d) May 1 of the year following the year in which the NO_X Budget unit commences operation, if the unit commences operation on or after October 1 of the year.

§ 96.25 NO_X Budget permit revisions.

(a) For a NO_X Budget source with a title V operating permit, except as provided in § 96.23(b), the permitting authority will revise the NO_X Budget permit, as necessary, in accordance with the permitting authority's title V operating permits regulations addressing permit revisions.

(b) For a NO_X Budget source with a non-title V permit, except as provided in § 96.23(b), the permitting authority will revise the NO_X Budget permit, as necessary, in accordance with the permitting authority's non-title V permits regulations addressing permit revisions.

Subpart D—Compliance Certification

§ 96.30 Compliance certification report.

(a) *Applicability and deadline.* For each control period in which one or more NO_X Budget units at a source are subject to the NO_X Budget emissions limitation, the NO_X authorized account representative of the source shall submit to the permitting authority and the Administrator by November 30 of that year, a compliance certification report for each source covering all such units.

(b) *Contents of report.* The NO_X authorized account representative shall include in the compliance certification report under paragraph (a) of this section the following elements, in a format prescribed by the Administrator, concerning each unit at the source and subject to the NO_X Budget emissions limitation for the control period covered by the report:

(1) Identification of each NO_X Budget unit;

(2) At the NO_X authorized account representative's option, the serial numbers of the NO_X allowances that are to be deducted from each unit's compliance account under § 96.54 for the control period;

(3) At the NO_X authorized account representative's option, for units sharing a common stack and having NO_X emissions that are not monitored separately or apportioned in accordance with subpart H of this part, the percentage of allowances that is to be deducted from each unit's compliance account under § 96.54(e); and

(4) The compliance certification under paragraph (c) of this section.

(c) *Compliance certification.* In the compliance certification report under paragraph (a) of this section, the NO_X authorized account representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the source and the NO_X Budget units at the source in compliance with the NO_X Budget Trading Program, whether each NO_X Budget unit for which the compliance certification is submitted was operated during the calendar year covered by the report in compliance with the requirements of the NO_X Budget Trading Program applicable to the unit, including:

(1) Whether the unit was operated in compliance with the NO_X Budget emissions limitation;

(2) Whether the monitoring plan that governs the unit has been maintained to reflect the actual operation and monitoring of the unit, and contains all information necessary to attribute NO_X emissions to the unit, in accordance with subpart H of this part;

(3) Whether all the NO_X emissions from the unit, or a group of units (including the unit) using a common stack, were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports, including whether conditional data were reported in the quarterly reports in accordance with subpart H of this part. If conditional data were reported, the owner or operator shall indicate whether the status of all conditional data has been resolved and all necessary quarterly report resubmissions has been made;

(4) Whether the facts that form the basis for certification under subpart H of this part of each monitor at the unit or a group of units (including the unit) using a common stack, or for using an excepted monitoring method or alternative monitoring method approved under subpart H of this part, if any, has changed; and

(5) If a change is required to be reported under paragraph (c)(4) of this section, specify the nature of the change, the reason for the change, when the change occurred, and how the unit's compliance status was determined subsequent to the change, including what method was used to determine emissions when a change mandated the need for monitor recertification.

§ 96.31 Permitting authority's and Administrator's action on compliance certifications.

(a) The permitting authority or the Administrator may review and conduct independent audits concerning any compliance certification or any other submission under the NO_X Budget Trading Program and make appropriate adjustments of the information in the compliance certifications or other submissions.

(b) The Administrator may deduct NO_X allowances from or transfer NO_X allowances to a unit's compliance account or a source's overdraft account based on the information in the compliance certifications or other submissions, as adjusted under paragraph (a) of this section.

Subpart E—NO_X Allowance Allocations

§ 96.40 State trading program budget.

The State trading program budget allocated by the permitting authority under § 96.42 for a control period will equal the total number of tons of NO_X emissions apportioned to the NO_X Budget units under § 96.4 in the State for the control period, as determined by the applicable, approved State implementation plan.

§ 96.41 Timing requirements for NO_X allowance allocations.

(a) By September 30, 1999, the permitting authority will submit to the Administrator the NO_X allowance allocations, in accordance with § 96.42, for the control periods in 2003, 2004, and 2005.

(b) By April 1, 2003 and April 1 of each year thereafter, the permitting authority will submit to the Administrator the NO_X allowance allocations, in accordance with § 96.42, for the control period in the year that is three years after the year of the applicable deadline for submission under this paragraph (b). If the permitting authority fails to submit to the Administrator the NO_X allowance allocations in accordance with this paragraph (b), the Administrator will allocate, for the applicable control period, the same number of NO_X allowances as were allocated for the preceding control period.

(c) By April 1, 2004 and April 1 of each year thereafter, the permitting authority will submit to the Administrator the NO_X allowance allocations, in accordance with § 96.42, for any NO_X allowances remaining in the allocation set-aside for the prior control period.

§ 96.42 NO_X allowance allocations.

(a)(1) The heat input (in mmBtu) used for calculating NO_X allowance allocations for each NO_X Budget unit under § 96.4 will be:

(i) For a NO_X allowance allocation under § 96.41(a), the average of the two highest amounts of the unit's heat input for the control periods in 1995, 1996, and 1997 if the unit is under § 96.4(a)(1) or the control period in 1995 if the unit is under § 96.4(a)(2); and

(ii) For a NO_X allowance allocation under § 96.41(b), the unit's heat input for the control period in the year that is four years before the year for which the NO_X allocation is being calculated.

(2) The unit's total heat input for the control period in each year specified under paragraph (a)(1) of this section will be determined in accordance with part 75 of this chapter if the NO_X Budget unit was otherwise subject to the requirements of part 75 of this chapter for the year, or will be based on the best available data reported to the permitting authority for the unit if the unit was not otherwise subject to the requirements of part 75 of this chapter for the year.

(b) For each control period under § 96.41, the permitting authority will allocate to all NO_X Budget units under § 96.4(a)(1) in the State that commenced operation before May 1 of the period used to calculate heat input under paragraph (a)(1) of this section, a total number of NO_X allowances equal to 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the tons of NO_X emissions in the State trading program budget apportioned to electric generating units under § 96.40 in accordance with the following procedures:

(1) The permitting authority will allocate NO_X allowances to each NO_X Budget unit under § 96.4(a)(1) in an amount equaling 0.15 lb/mmBtu multiplied by the heat input determined under paragraph (a) of this section, rounded to the nearest whole NO_X allowance as appropriate.

(2) If the initial total number of NO_X allowances allocated to all NO_X Budget units under § 96.4(a)(1) in the State for a control period under paragraph (b)(1) of this section does not equal 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NO_X emissions in the State trading program

budget apportioned to electric generating units, the permitting authority will adjust the total number of NO_X allowances allocated to all such NO_X Budget units for the control period under paragraph (b)(1) of this section so that the total number of NO_X allowances allocated equals 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NO_X emissions in the State trading program budget apportioned to electric generating units. This adjustment will be made by: multiplying each unit's allocation by 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NO_X emissions in the State trading program budget apportioned to electric generating units divided by the total number of NO_X allowances allocated under paragraph (b)(1) of this section, and rounding to the nearest whole NO_X allowance as appropriate.

(c) For each control period under § 96.41, the permitting authority will allocate to all NO_X Budget units under § 96.4(a)(2) in the State that commenced operation before May 1 of the period used to calculate heat input under paragraph (a)(1) of this section, a total number of NO_X allowances equal to 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the tons of NO_X emissions in the State trading program budget apportioned to non-electric generating units under § 96.40 in accordance with the following procedures:

(1) The permitting authority will allocate NO_X allowances to each NO_X Budget unit under § 96.4(a)(2) in an amount equaling 0.17 lb/mmBtu multiplied by the heat input determined under paragraph (a) of this section, rounded to the nearest whole NO_X allowance as appropriate.

(2) If the initial total number of NO_X allowances allocated to all NO_X Budget units under § 96.4(a)(2) in the State for a control period under paragraph (c)(1) of this section does not equal 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NO_X emissions in the State trading program budget apportioned to non-electric generating units, the permitting authority will adjust the total number of NO_X allowances allocated to all such NO_X Budget units for the control period under paragraph (c)(1) of this section so that the total number of NO_X allowances allocated equals 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NO_X emissions in the State trading program budget apportioned to non-electric generating units. This adjustment will be made by: multiplying each unit's allocation by 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NO_X emissions in the State trading program budget apportioned to non-electric generating units divided by the total number of NO_X allowances allocated under paragraph (c)(1) of this section, and rounding to the nearest whole NO_X allowance as appropriate.

(d) For each control period under § 96.41, the permitting authority will allocate NO_X allowances to NO_X Budget units under § 96.4 in the State that commenced operation, or is projected to commence operation, on or after May 1 of the period used to calculate heat input under paragraph (a)(1) of this section, in accordance with the following procedures:

(1) The permitting authority will establish one allocation set-aside for each control period. Each allocation set-aside will be allocated NO_X allowances equal to 5 percent in 2003, 2004, and 2005, or 2 percent thereafter, of the tons of NO_X emissions in the State trading program budget under § 96.40, rounded to the nearest whole NO_X allowance as appropriate.

(2) The NO_X authorized account representative of a NO_X Budget unit under paragraph (d) of this section may submit to the permitting authority a request, in writing or in a format specified by the permitting authority, to be allocated NO_X allowances for no more than five consecutive control periods under § 96.41, starting with the control period during which the NO_X Budget unit commenced, or is projected to commence, operation and ending with the control period preceding the control period for which it will receive an allocation under paragraph (b) or (c) of this section. The NO_X allowance allocation request must be submitted prior to May 1 of the first control period for which the NO_X allowance allocation is requested and after the date on which the permitting authority issues a permit to construct the NO_X Budget unit.

(3) In a NO_X allowance allocation request under paragraph (d)(2) of this section, the NO_X authorized account representative for units under § 96.4(a)(1) may request for a control period NO_X allowances in an amount that does not exceed 0.15 lb/mmBtu multiplied by the NO_X Budget unit's maximum design heat input (in mmBtu/hr) multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate.

(4) In a NO_X allowance allocation request under paragraph (d)(2) of this section, the NO_X authorized account representative for units under § 96.4(a)(2) may request for a control period NO_X allowances in an amount that does not exceed 0.17 lb/mmBtu multiplied by the NO_X Budget unit's maximum design heat input (in mmBtu/hr) multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate.

(5) The permitting authority will review, and allocate NO_X allowances pursuant to, each NO_X allowance allocation request under paragraph (d)(2) of this section in the order that the request is received by the permitting authority.

(i) Upon receipt of the NO_X allowance allocation request, the permitting authority will determine whether, and will make any necessary adjustments to the request to ensure that, for units under § 96.4(a)(1), the control period and the number of allowances specified are consistent with the requirements of paragraphs (d)(2) and (3) of this section and, for units under § 96.4(a)(2), the control period and the number of allowances specified are consistent with the requirements of paragraphs (d)(2) and (4) of this section.

(ii) If the allocation set-aside for the control period for which NO_X allowances are requested has an amount of NO_X allowances not less than the number requested (as adjusted under paragraph (d)(5)(i) of this section), the permitting authority will allocate the amount of the NO_X allowances requested (as adjusted under paragraph (d)(5)(i) of this section) to the NO_X Budget unit.

(iii) If the allocation set-aside for the control period for which NO_X allowances are requested has a smaller amount of NO_X allowances than the number requested (as adjusted under paragraph (d)(5)(i) of this section), the permitting authority will deny in part the request and allocate only the remaining number of NO_X allowances in the allocation set-aside to the NO_X Budget unit.

(iv) Once an allocation set-aside for a control period has been depleted of all NO_X allowances, the permitting authority will deny, and will not allocate any NO_X allowances pursuant to, any NO_X allowance allocation request under which NO_X allowances have not already been allocated for the control period.

(6) Within 60 days of receipt of a NO_X allowance allocation request, the permitting authority will take appropriate action under paragraph (d)(5) of this section and notify the NO_X authorized account representative that submitted the request and the Administrator of the number of NO_X

allowances (if any) allocated for the control period to the NO_X Budget unit.

(e) For a NO_X Budget unit that is allocated NO_X allowances under paragraph (d) of this section for a control period, the Administrator will deduct NO_X allowances under § 96.54(b) or (e) to account for the actual utilization of the unit during the control period. The Administrator will calculate the number of NO_X allowances to be deducted to account for the unit's actual utilization using the following formulas and rounding to the nearest whole NO_X allowance as appropriate, provided that the number of NO_X allowances to be deducted shall be zero if the number calculated is less than zero:

NO_X allowances deducted for actual utilization for units under § 96.4(a)(1) = (Unit's NO_X allowances allocated for control period) − (Unit's actual control period utilization × 0.15 lb/mmBtu); and

NO_X allowances deducted for actual utilization for units under § 96.4(a)(2) = (Unit's NO_X allowances allocated for control period) − (Unit's actual control period utilization × 0.17 lb/mmBtu)

Where:

''Unit's NO_X allowances allocated for control period'' is the number of NO_X allowances allocated to the unit for the control period under paragraph (d) of this section; and

''Unit's actual control period utilization'' is the utilization (in mmBtu), as defined in § 96.2, of the unit during the control period.

(f) After making the deductions for compliance under § 96.54(b) or (e) for a control period, the Administrator will notify the permitting authority whether any NO_X allowances remain in the allocation set-aside for the control period. The permitting authority will allocate any such NO_X allowances to the NO_X Budget units in the State using the following formula and rounding to the nearest whole NO_X allowance as appropriate:

Unit's share of NO_X allowances remaining in allocation set-aside = Total NO_X allowances remaining in allocation set-aside × (Unit's NO_X allowance allocation ÷ (State trading program budget excluding allocation set-aside)

Where:

''Total NO_X allowances remaining in allocation set-aside'' is the total number of NO_X allowances remaining in the allocation set-aside for the control period to which the allocation set-aside applies;

''Unit's NO_X allowance allocation'' is the number of NO_X allowances allocated under paragraph (b) or (c) of this section to the unit for the control period to which the allocation set-aside applies; and

''State trading program budget excluding allocation set-aside'' is the State trading program budget under § 96.40 for the control period to which the allocation set-aside applies multiplied by 95 percent if the control period is in 2003, 2004, or 2005 or 98 percent if the control period is in any year thereafter, rounded to the nearest whole NO_X allowance as appropriate.

Subpart F—NO_X Allowance Tracking System

§ 96.50 NO_X Allowance Tracking System accounts.

(a) *Nature and function of compliance accounts and overdraft accounts.* Consistent with § 96.51(a), the Administrator will establish one compliance account for each NO_X Budget unit and one overdraft account for each source with one or more NO_X Budget units. Allocations of NO_X allowances pursuant to subpart E of this part or § 96.88 and deductions or transfers of NO_X allowances pursuant to § 96.31, § 96.54, § 96.56, subpart G of this part, or subpart I of this part will be recorded in the compliance accounts or overdraft accounts in accordance with this subpart.

(b) *Nature and function of general accounts.* Consistent with § 96.51(b), the Administrator will establish, upon request, a general account for any person. Transfers of allowances pursuant to subpart G of this part will be recorded in the general account in accordance with this subpart.

§ 96.51 Establishment of accounts.

(a) *Compliance accounts and overdraft accounts.* Upon receipt of a complete account certificate of representation under § 96.13, the Administrator will establish:

(1) A compliance account for each NO_X Budget unit for which the account certificate of representation was submitted; and

(2) An overdraft account for each source for which the account certificate of representation was submitted and that has two or more NO_X Budget units.

(b) *General accounts.* (1) Any person may apply to open a general account for the purpose of holding and transferring allowances. A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(i) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the NO_X authorized account representative and any alternate NO_X authorized account representative;

(ii) At the option of the NO_X authorized account representative, organization name and type of organization;

(iii) A list of all persons subject to a binding agreement for the NO_X authorized account representative or any alternate NO_X authorized account representative to represent their ownership interest with respect to the allowances held in the general account;

(iv) The following certification statement by the NO_X authorized account representative and any alternate NO_X authorized account representative: ''I certify that I was selected as the NO_X authorized account representative or the NO_X alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the NO_X Budget Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account.''

(v) The signature of the NO_X authorized account representative and any alternate NO_X authorized account representative and the dates signed.

(vi) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the account certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(i) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(ii) The NO_X authorized account representative and any alternate NO_X authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to NO_X allowances held in the general account in all matters pertaining to the NO_X Budget Trading Program, not withstanding any agreement between the NO_X authorized account representative or any alternate NO_X authorized account representative and such person. Any such person shall be bound by any order or decision issued to the NO_X authorized account representative or any alternate NO_X authorized account representative by the Administrator or a court regarding the general account.

(iii) Each submission concerning the general account shall be submitted, signed, and certified by the NO_X authorized account representative or any alternate NO_X authorized account representative for the persons having an ownership interest with respect to NO_X allowances held in the general account. Each such submission shall include the following certification statement by the NO_X authorized account representative or any alternate NO_X authorized account representative any: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the NO_X allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iv) The Administrator will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(iii) of this section.

(3)(i) An application for a general account may designate one and only one NO_X authorized account representative and one and only one alternate NO_X authorized account representative who may act on behalf of the NO_X authorized account representative. The agreement by which the alternate NO_X authorized account representative is selected shall include a procedure for authorizing the alternate NO_X authorized account representative to act in lieu of the NO_X authorized account representative.

(ii) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, any representation, action, inaction, or submission by any alternate NO_X authorized account representative shall be deemed to be a representation, action, inaction, or submission by the NO_X authorized account representative.

(4)(i) The NO_X authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous NO_X authorized account representative prior to the time and date when the Administrator receives the superseding application for a general account shall be binding on the new NO_X authorized account representative and the persons with an ownership interest with respect to the allowances in the general account.

(ii) The alternate NO_X authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate NO_X authorized account representative prior to the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate NO_X authorized account representative and the persons with an ownership interest with respect to the allowances in the general account.

(iii)(A) In the event a new person having an ownership interest with respect to NO_X allowances in the general account is not included in the list of such persons in the account certificate of representation, such new person shall be deemed to be subject to and bound by the account certificate of representation, the representation, actions, inactions, and submissions of the NO_X authorized account representative and any alternate NO_X authorized account representative of the source or unit, and the decisions, orders, actions, and inactions of the Administrator, as if the new person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to NO_X allowances in the general account, including the addition of persons, the NO_X authorized account representative or any alternate NO_X authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the NO_X allowances in the general account to include the change.

(5)(i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(4) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the NO_X authorized account representative or any alternate NO_X authorized account representative for a general account shall affect any representation, action, inaction, or submission of the NO_X authorized account representative or any alternate NO_X authorized account representative or the finality of any decision or order by the Administrator under the NO_X Budget Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the NO_X authorized account representative or any alternate NO_X authorized account representative for a general account, including private legal disputes concerning the proceeds of NO_X allowance transfers.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

§ 96.52 NO_X Allowance Tracking System responsibilities of NO_X authorized account representative.

(a) Following the establishment of a NO_X Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of NO_X allowances in the account, shall be made only by the NO_X authorized account representative for the account.

(b) *Authorized account representative identification.* The Administrator will assign a unique identifying number to each NO_X authorized account representative.

§ 96.53 Recordation of NO_X allowance allocations.

(a) The Administrator will record the NO_X allowances for 2003 in the NO_X Budget units' compliance accounts and the allocation set-asides, as allocated under subpart E of this part. The Administrator will also record the NO_X allowances allocated under § 96.88(a)(1) for each NO_X Budget opt-in source in its compliance account.

(b) Each year, after the Administrator has made all deductions from a NO_X Budget unit's compliance account and the overdraft account pursuant to § 96.54, the Administrator will record

NO_X allowances, as allocated to the unit under subpart E of this part or under § 96.88(a)(2), in the compliance account for the year after the last year for which allowances were previously allocated to the compliance account. Each year, the Administrator will also record NO_X allowances, as allocated under subpart E of this part, in the allocation set-aside for the year after the last year for which allowances were previously allocated to an allocation set-aside.

(c) *Serial numbers for allocated NO_X allowances.* When allocating NO_X allowances to and recording them in an account, the Administrator will assign each NO_X allowance a unique identification number that will include digits identifying the year for which the NO_X allowance is allocated.

§ 96.54 Compliance.

(a) *NO_X allowance transfer deadline.* The NO_X allowances are available to be deducted for compliance with a unit's NO_X Budget emissions limitation for a control period in a given year only if the NO_X allowances:

(1) Were allocated for a control period in a prior year or the same year; and

(2) Are held in the unit's compliance account, or the overdraft account of the source where the unit is located, as of the NO_X allowance transfer deadline for that control period or are transferred into the compliance account or overdraft account by a NO_X allowance transfer correctly submitted for recordation under § 96.60 by the NO_X allowance transfer deadline for that control period.

(b) *Deductions for compliance.* (1) Following the recordation, in accordance with § 96.61, of NO_X allowance transfers submitted for recordation in the unit's compliance account or the overdraft account of the source where the unit is located by the NO_X allowance transfer deadline for a control period, the Administrator will deduct NO_X allowances available under paragraph (a) of this section to cover the unit's NO_X emissions (as determined in accordance with subpart H of this part), or to account for actual utilization under § 96.42(e), for the control period:

(i) From the compliance account; and

(ii) Only if no more NO_X allowances available under paragraph (a) of this section remain in the compliance account, from the overdraft account. In deducting allowances for units at the source from the overdraft account, the Administrator will begin with the unit having the compliance account with the lowest NO_X Allowance Tracking System account number and end with the unit having the compliance account with the highest NO_X Allowance Tracking System account number (with account numbers sorted beginning with the left-most character and ending with the right-most character and the letter characters assigned values in alphabetical order and less than all numeric characters).

(2) The Administrator will deduct NO_X allowances first under paragraph (b)(1)(i) of this section and then under paragraph (b)(1)(ii) of this section:

(i) Until the number of NO_X allowances deducted for the control period equals the number of tons of NO_X emissions, determined in accordance with subpart H of this part, from the unit for the control period for which compliance is being determined, plus the number of NO_X allowances required for deduction to account for actual utilization under § 96.42(e) for the control period; or

(ii) Until no more NO_X allowances available under paragraph (a) of this section remain in the respective account.

(c)(1) *Identification of NO_X allowances by serial number.* The NO_X authorized account representative for each compliance account may identify by serial number the NO_X allowances to be deducted from the unit's compliance account under paragraph (b), (d), or (e) of this section. Such identification shall be made in the compliance certification report submitted in accordance with § 96.30.

(2) *First-in, first-out.* The Administrator will deduct NO_X allowances for a control period from the compliance account, in the absence of an identification or in the case of a partial identification of NO_X allowances by serial number under paragraph (c)(1) of this section, or the overdraft account on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Those NO_X allowances that were allocated for the control period to the unit under subpart E or I of this part;

(ii) Those NO_X allowances that were allocated for the control period to any unit and transferred and recorded in the account pursuant to subpart G of this part, in order of their date of recordation;

(iii) Those NO_X allowances that were allocated for a prior control period to the unit under subpart E or I of this part; and

(iv) Those NO_X allowances that were allocated for a prior control period to any unit and transferred and recorded in the account pursuant to subpart G of this part, in order of their date of recordation.

(d) *Deductions for excess emissions.* (1) After making the deductions for compliance under paragraph (b) of this section, the Administrator will deduct from the unit's compliance account or the overdraft account of the source where the unit is located a number of NO_X allowances, allocated for a control period after the control period in which the unit has excess emissions, equal to three times the number of the unit's excess emissions.

(2) If the compliance account or overdraft account does not contain sufficient NO_X allowances, the Administrator will deduct the required number of NO_X allowances, regardless of the control period for which they were allocated, whenever NO_X allowances are recorded in either account.

(3) Any allowance deduction required under paragraph (d) of this section shall not affect the liability of the owners and operators of the NO_X Budget unit for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under the CAA or applicable State law. The following guidelines will be followed in assessing fines, penalties or other obligations:

(i) For purposes of determining the number of days of violation, if a NO_X Budget unit has excess emissions for a control period, each day in the control period (153 days) constitutes a day in violation unless the owners and operators of the unit demonstrate that a lesser number of days should be considered.

(ii) Each ton of excess emissions is a separate violation.

(e) *Deductions for units sharing a common stack.* In the case of units sharing a common stack and having emissions that are not separately monitored or apportioned in accordance with subpart H of this part:

(1) The NO_X authorized account representative of the units may identify the percentage of NO_X allowances to be deducted from each such unit's compliance account to cover the unit's share of NO_X emissions from the common stack for a control period. Such identification shall be made in the compliance certification report submitted in accordance with § 96.30.

(2) Notwithstanding paragraph (b)(2)(i) of this section, the Administrator will deduct NO_X allowances for each such unit until the number of NO_X allowances deducted equals the unit's identified percentage (under paragraph (e)(1) of this section) of the number of tons of NO_X emissions, as determined in accordance with subpart H of this part, from the common stack for the control period for which compliance is being determined or, if no percentage is identified, an equal

percentage for each such unit, plus the number of allowances required for deduction to account for actual utilization under § 96.42(e) for the control period.

(f) The Administrator will record in the appropriate compliance account or overdraft account all deductions from such an account pursuant to paragraphs (b), (d), or (e) of this section.

§ 96.55 Banking.

(a) NO_X allowances may be banked for future use or transfer in a compliance account, an overdraft account, or a general account, as follows:

(1) Any NO_X allowance that is held in a compliance account, an overdraft account, or a general account will remain in such account unless and until the NO_X allowance is deducted or transferred under § 96.31, § 96.54, § 96.56, subpart G of this part, or subpart I of this part.

(2) The Administrator will designate, as a ''banked'' NO_X allowance, any NO_X allowance that remains in a compliance account, an overdraft account, or a general account after the Administrator has made all deductions for a given control period from the compliance account or overdraft account pursuant to § 96.54.

(b) Each year starting in 2004, after the Administrator has completed the designation of banked NO_X allowances under paragraph (a)(2) of this section and before May 1 of the year, the Administrator will determine the extent to which banked NO_X allowances may be used for compliance in the control period for the current year, as follows:

(1) The Administrator will determine the total number of banked NO_X allowances held in compliance accounts, overdraft accounts, or general accounts.

(2) If the total number of banked NO_X allowances determined, under paragraph (b)(1) of this section, to be held in compliance accounts, overdraft accounts, or general accounts is less than or equal to 10% of the sum of the State trading program budgets for the control period for the States in which NO_X Budget units are located, any banked NO_X allowance may be deducted for compliance in accordance with § 96.54.

(3) If the total number of banked NO_X allowances determined, under paragraph (b)(1) of this section, to be held in compliance accounts, overdraft accounts, or general accounts exceeds 10% of the sum of the State trading program budgets for the control period for the States in which NO_X Budget units are located, any banked allowance may be deducted for compliance in accordance with § 96.54, except as follows:

(i) The Administrator will determine the following ratio: 0.10 multiplied by the sum of the State trading program budgets for the control period for the States in which NO_X Budget units are located and divided by the total number of banked NO_X allowances determined, under paragraph (b)(1) of this section, to be held in compliance accounts, overdraft accounts, or general accounts.

(ii) The Administrator will multiply the number of banked NO_X allowances in each compliance account or overdraft account. The resulting product is the number of banked NO_X allowances in the account that may be deducted for compliance in accordance with § 96.54. Any banked NO_X allowances in excess of the resulting product may be deducted for compliance in accordance with § 96.54, except that, if such NO_X allowances are used to make a deduction, two such NO_X allowances must be deducted for each deduction of one NO_X allowance required under § 96.54.

(c) Any NO_X Budget unit may reduce its NO_X emission rate in the 2001 or 2002 control period, the owner or operator of the unit may request early reduction credits, and the permitting authority may allocate NO_X allowances in 2003 to the unit in accordance with the following requirements.

(1) Each NO_X Budget unit for which the owner or operator requests any early reduction credits under paragraph (c)(4) of this section shall monitor NO_X emissions in accordance with subpart H of this part starting in the 2000 control period and for each control period for which such early reduction credits are requested. The unit's monitoring system availability shall be not less than 90 percent during the 2000 control period, and the unit must be in compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) NO_X emission rate and heat input under paragraphs (c)(3) through (5) of this section shall be determined in accordance with subpart H of this part.

(3) Each NO_X Budget unit for which the owner or operator requests any early reduction credits under paragraph (c)(4) of this section shall reduce its NO_X emission rate, for each control period for which early reduction credits are requested, to less than both 0.25 lb/mmBtu and 80 percent of the unit's NO_X emission rate in the 2000 control period.

(4) The NO_X authorized account representative of a NO_X Budget unit that meets the requirements of paragraphs (c)(1)and (3) of this section may submit to the permitting authority a request for early reduction credits for the unit based on NO_X emission rate reductions made by the unit in the control period for 2001 or 2002 in accordance with paragraph (c)(3) of this section.

(i) In the early reduction credit request, the NO_X authorized account may request early reduction credits for such control period in an amount equal to the unit's heat input for such control period multiplied by the difference between 0.25 lb/mmBtu and the unit's NO_X emission rate for such control period, divided by 2000 lb/ton, and rounded to the nearest ton.

(ii) The early reduction credit request must be submitted, in a format specified by the permitting authority, by October 31 of the year in which the NO_X emission rate reductions on which the request is based are made or such later date approved by the permitting authority.

(5) The permitting authority will allocate NO_X allowances, to NO_X Budget units meeting the requirements of paragraphs (c)(1) and (3) of this section and covered by early reduction requests meeting the requirements of paragraph (c)(4)(ii) of this section, in accordance with the following procedures:

(i) Upon receipt of each early reduction credit request, the permitting authority will accept the request only if the requirements of paragraphs (c)(1), (c)(3), and (c)(4)(ii) of this section are met and, if the request is accepted, will make any necessary adjustments to the request to ensure that the amount of the early reduction credits requested meets the requirement of paragraphs (c)(2) and (4) of this section.

(ii) If the State's compliance supplement pool has an amount of NO_X allowances not less than the number of early reduction credits in all accepted early reduction credit requests for 2001 and 2002 (as adjusted under paragraph (c)(5)(i) of this section), the permitting authority will allocate to each NO_X Budget unit covered by such accepted requests one allowance for each early reduction credit requested (as adjusted under paragraph (c)(5)(i) of this section).

(iii) If the State's compliance supplement pool has a smaller amount of NO_X allowances than the number of early reduction credits in all accepted early reduction credit requests for 2001 and 2002 (as adjusted under paragraph (c)(5)(i) of this section), the permitting authority will allocate NO_X allowances to each NO_X Budget unit covered by such accepted requests according to the following formula:

Unit's allocated early reduction credits = [(Unit's adjusted early reduction credits) / (Total adjusted early reduction credits requested by all units)] x (Available NO_X allowances from the State's compliance supplement pool)

where:

''Unit's adjusted early reduction credits'' is the number of early reduction credits for the unit for 2001 and 2002 in accepted early reduction credit requests, as adjusted under paragraph (c)(5)(i) of this section.

''Total adjusted early reduction credits requested by all units'' is the number of early reduction credits for all units for 2001 and 2002 in accepted early reduction credit requests, as adjusted under paragraph (c)(5)(i) of this section.

''Available NO_X allowances from the State's compliance supplement pool'' is the number of NO_X allowances in the State's compliance supplement pool and available for early reduction credits for 2001 and 2002.

(6) By May 1, 2003, the permitting authority will submit to the Administrator the allocations of NO_X allowances determined under paragraph (c)(5) of this section. The Administrator will record such allocations to the extent that they are consistent with the requirements of paragraphs (c)(1) through (5) of this section.

(7) NO_X allowances recorded under paragraph (c)(6) of this section may be deducted for compliance under § 96.54 for the control periods in 2003 or 2004. Notwithstanding paragraph (a) of this section, the Administrator will deduct as retired any NO_X allowance that is recorded under paragraph (c)(6) of this section and is not deducted for compliance in accordance with § 96.54 for the control period in 2003 or 2004.

(8) NO_X allowances recorded under paragraph (c)(6) of this section are treated as banked allowances in 2004 for the purposes of paragraphs (a) and (b) of this section.

§ 96.56 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any NO_X Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the NO_X authorized account representative for the account.

§ 96.57 Closing of general accounts.

(a) The NO_X authorized account representative of a general account may instruct the Administrator to close the account by submitting a statement requesting deletion of the account from the NO_X Allowance Tracking System and by correctly submitting for recordation under § 96.60 an allowance transfer of all NO_X allowances in the account to one or more other NO_X Allowance Tracking System accounts.

(b) If a general account shows no activity for a period of a year or more and does not contain any NO_X allowances, the Administrator may notify the NO_X authorized account representative for the account that the account will be closed and deleted from the NO_X Allowance Tracking System following 20 business days after the notice is sent. The account will be closed after the 20-day period unless before the end of the 20-day period the Administrator receives a correctly submitted transfer of NO_X allowances into the account under § 96.60 or a statement submitted by the NO_X authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

Subpart G—NO_X Allowance Transfers

§ 96.60 Submission of NO_X allowance transfers.

The NO_X authorized account representatives seeking recordation of a NO_X allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the NO_X allowance transfer shall include the following elements in a format specified by the Administrator:

(a) The numbers identifying both the transferor and transferee accounts;

(b) A specification by serial number of each NO_X allowance to be transferred; and

(c) The printed name and signature of the NO_X authorized account representative of the transferor account and the date signed.

§ 96.61 EPA recordation.

(a) Within 5 business days of receiving a NO_X allowance transfer, except as provided in paragraph (b) of this section, the Administrator will record a NO_X allowance transfer by moving each NO_X allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under § 96.60;

(2) The transferor account includes each NO_X allowance identified by serial number in the transfer; and

(3) The transfer meets all other requirements of this part.

(b) A NO_X allowance transfer that is submitted for recordation following the NO_X allowance transfer deadline and that includes any NO_X allowances allocated for a control period prior to or the same as the control period to which the NO_X allowance transfer deadline applies will not be recorded until after completion of the process of recordation of NO_X allowance allocations in § 96.53(b).

(c) Where a NO_X allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§ 96.62 Notification.

(a) *Notification of recordation.* Within 5 business days of recordation of a NO_X allowance transfer under § 96.61, the Administrator will notify each party to the transfer. Notice will be given to the NO_X authorized account representatives of both the transferror and transferee accounts.

(b) *Notification of non-recordation.* Within 10 business days of receipt of a NO_X allowance transfer that fails to meet the requirements of § 96.61(a), the Administrator will notify the NO_X authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and (2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a NO_X allowance transfer for recordation following notification of non-recordation.

Subpart H—Monitoring and Reporting

§ 96.70 General requirements.

The owners and operators, and to the extent applicable, the NO_X authorized account representative of a NO_X Budget unit, shall comply with the monitoring and reporting requirements as provided in this subpart and in subpart H of part 75 of this chapter. For purposes of complying with such requirements, the definitions in § 96.2 and in § 72.2 of this chapter shall apply, and the terms ''affected unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') in part 75 of this chapter shall be replaced by the terms ''NO_X Budget unit,'' ''NO_X authorized account representative,'' and ''continuous emission monitoring system'' (or ''CEMS''), respectively, as defined in § 96.2.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each NO_X Budget unit must meet the following requirements. These provisions also apply to a unit for which an application for a NO_X Budget opt-in permit is submitted and not denied or withdrawn, as provided in subpart I of this part:

(1) Install all monitoring systems required under this subpart for

monitoring NO_X mass. This includes all systems required to monitor NO_X emission rate, NO_X concentration, heat input, and flow, in accordance with §§ 75.72 and 75.76.

(2) Install all monitoring systems for monitoring heat input, if required under § 96.76 for developing NO_X allowance allocations.

(3) Successfully complete all certification tests required under § 96.71 and meet all other provisions of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraphs (a)(1) and (2) of this section.

(4) Record, and report data from the monitoring systems under paragraphs (a)(1) and (2) of this section.

(b) *Compliance dates.* The owner or operator must meet the requirements of paragraphs (a)(1) through (a)(3) of this section on or before the following dates and must record and report data on and after the following dates:

(1) NO_X Budget units for which the owner or operator intends to apply for early reduction credits under § 96.55(d) must comply with the requirements of this subpart by May 1, 2000.

(2) Except for NO_X Budget units under paragraph (b)(1) of this section, NO_X Budget units under § 96.4 that commence operation before January 1, 2002, must comply with the requirements of this subpart by May 1, 2002.

(3) NO_X Budget units under § 96.4 that commence operation on or after January 1, 2002 and that report on an annual basis under § 96.74(d) must comply with the requirements of this subpart by the later of the following dates:

(i) May 1, 2002; or

(ii) The earlier of:

(A) 180 days after the date on which the unit commences operation or, (B) For units under § 96.4(a)(1), 90 days after the date on which the unit commences commercial operation.

(4) NO_X Budget units under § 96.4 that commence operation on or after January 1, 2002 and that report on a control season basis under § 96.74(d) must comply with the requirements of this subpart by the later of the following dates:

(i) The earlier of:

(A) 180 days after the date on which the unit commences operation or,

(B) For units under § 96.4(a)(1), 90 days after the date on which the unit commences commercial operation.

(ii) However, if the applicable deadline under paragraph (b)(4)(i) section does not occur during a control period, May 1; immediately following the date determined in accordance with paragraph (b)(4)(i) of this section.

(5) For a NO_X Budget unit with a new stack or flue for which construction is completed after the applicable deadline under paragraph (b)(1), (b)(2) or (b)(3) of this section or subpart I of this part:

(i) 90 days after the date on which emissions first exit to the atmosphere through the new stack or flue;

(ii) However, if the unit reports on a control season basis under § 96.74(d) and the applicable deadline under paragraph (b)(5)(i) of this section does not occur during the control period, May 1 immediately following the applicable deadline in paragraph (b)(5)(i) of this section.

(6) For a unit for which an application for a NO_X Budget opt in permit is submitted and not denied or withdrawn, the compliance dates specified under subpart I of this part.

(c) *Reporting data prior to initial certification.* (1) The owner or operator of a NO_X Budget unit that misses the certification deadline under paragraph (b)(1) of this section is not eligible to apply for early reduction credits. The owner or operator of the unit becomes subject to the certification deadline under paragraph (b)(2) of this section.

(2) The owner or operator of a NO_X Budget under paragraphs (b)(3) or (b)(4) of this section must determine, record and report NO_X mass, heat input (if required for purposes of allocations) and any other values required to determine NO_X Mass (e.g. NO_X emission rate and heat input or NO_X concentration and stack flow) using the provisions of § 75.70(g) of this chapter, from the date and hour that the unit starts operating until all required certification tests are successfully completed.

(d) *Prohibitions.* (1) No owner or operator of a NO_X Budget unit or a non-NO_X Budget unit monitored under § 75.72(b)(2)(ii) shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained prior written approval in accordance with § 96.75.

(2) No owner or operator of a NO_X Budget unit or a non-NO_X Budget unit monitored under § 75.72(b)(2)(ii) shall operate the unit so as to discharge, or allow to be discharged, NO_X emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter except as provided for in § 75.74 of this chapter.

(3) No owner or operator of a NO_X Budget unit or a non-NO_X Budget unit monitored under § 75.72(b)(2)(ii) shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter except as provided for in § 75.74 of this chapter.

(4) No owner or operator of a NO_X Budget unit or a non-NO_X Budget unit monitored under § 75.72(b)(2)(ii) shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved emission monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by a retired unit exemption under § 96.5 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the permitting authority for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The NO_X authorized account representative submits notification of the date of certification testing of a replacement monitoring system in accordance with § 96.71(b)(2).

§ 96.71 Initial certification and recertification procedures

(a) The owner or operator of a NO_X Budget unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures of part 75 of this chapter, except that:

(1) If, prior to January 1, 1998, the Administrator approved a petition under § 75.17(a) or (b) of this chapter for apportioning the NO_X emission rate measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.17 of this chapter, the NO_X authorized account representative shall resubmit the petition to the Administrator under § 96.75(a) to determine if the approval applies under the NO_X Budget Trading Program.

(2) For any additional CEMS required under the common stack provisions in § 75.72 of this chapter, or for any NO_X concentration CEMS used under the provisions of § 75.71(a)(2) of this chapter, the owner or operator shall

meet the requirements of paragraph (b) of this section.

(b) The owner or operator of a NO_X Budget unit that is not subject to an Acid Rain emissions limitation shall comply with the following initial certification and recertification procedures, except that the owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 shall also meet the requirements of paragraph (c) of this section and the owner or operator of a unit that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall also meet the requirements of paragraph (d) of this section. The owner or operator of a NO_X Budget unit that is subject to an Acid Rain emissions limitation, but requires additional CEMS under the common stack provisions in § 75.72 of this chapter, or that uses a NO_X concentration CEMS under § 75.71(a)(2) of this chapter also shall comply with the following initial certification and recertification procedures.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each monitoring system required by subpart H of part 75 of this chapter (which includes the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter. The owner or operator shall ensure that all applicable certification tests are successfully completed by the deadlines specified in § 96.70(b). In addition, whenever the owner or operator installs a monitoring system in order to meet the requirements of this part in a location where no such monitoring system was previously installed, initial certification according to § 75.20 is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in a certified monitoring system that the Administrator or the permitting authority determines significantly affects the ability of the system to accurately measure or record NO_X mass emissions or heat input or to meet the requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system according to § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that the Administrator or the permitting authority determines to significantly change the flow or concentration profile, the owner or operator shall recertify the continuous emissions monitoring system according to § 75.20(b) of this chapter. Examples of changes which require recertification include: replacement of the analyzer, change in location or orientation of the sampling probe or site, or changing of flow rate monitor polynomial coefficients.

(3) *Certification approval process for initial certifications and recertification.* (i) *Notification of certification.* The NO_X authorized account representative shall submit to the permitting authority, the appropriate EPA Regional Office and the permitting authority a written notice of the dates of certification in accordance with § 96.73.

(ii) *Certification application.* The NO_X authorized account representative shall submit to the permitting authority a certification application for each monitoring system required under subpart H of part 75 of this chapter. A complete certification application shall include the information specified in subpart H of part 75 of this chapter.

(iii) Except for units using the low mass emission excepted methodology under § 75.19 of this chapter, the provisional certification date for a monitor shall be determined using the procedures set forth in § 75.20(a)(3) of this chapter. A provisionally certified monitor may be used under the NO_X Budget Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system or component thereof under paragraph (b)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system or component thereof, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete certification application by the permitting authority.

(iv) *Certification application formal approval process.* The permitting authority will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (b)(3)(ii) of this section. In the event the permitting authority does not issue such a notice within such 120-day period, each monitoring system which meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the NO_X Budget Trading Program.

(A) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the permitting authority will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* A certification application will be considered complete when all of the applicable information required to be submitted under paragraph (b)(3)(ii) of this section has been received by the permitting authority. If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the NO_X authorized account representative must submit the additional information required to complete the certification application. If the NO_X authorized account representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (b)(3)(iv)(C) of this section.

(C) *Disapproval notice.* If the certification application shows that any monitoring system or component thereof does not meet the performance requirements of this part, or if the certification application is incomplete and the requirement for disapproval under paragraph (b)(3)(iv)(B) of this section has been met, the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system or component thereof shall not be considered valid quality-assured data beginning with the date and hour of provisional certification. The owner or operator shall follow the procedures for loss of certification in paragraph (b)(3)(v) of this section for each monitoring system or component thereof which is disapproved for initial certification.

(D) *Audit decertification.* The permitting authority may issue a notice of disapproval of the certification status of a monitor in accordance with § 96.72(b).

(v) *Procedures for loss of certification.* If the permitting authority issues a notice of disapproval of a certification application under paragraph (b)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (b)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each hour of unit operation during the period of invalid data beginning with the date and hour of provisional certification and continuing until the time, date, and hour specified under § 75.20(a)(5)(i) of this chapter:

(1) For units using or intending to monitor for NO_X emission rate and heat input or for units using the low mass emission excepted methodology under § 75.19 of this chapter, the maximum potential NO_X emission rate and the maximum potential hourly heat input of the unit.

(2) For units intending to monitor for NO_X mass emissions using a NO_X pollutant concentration monitor and a flow monitor, the maximum potential concentration of NO_X and the maximum potential flow rate of the unit under section 2.1 of appendix A of part 75 of this chapter;

(B) The NO_X authorized account representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (b)(3)(i) and (ii) of this section; and

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the permitting authority's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(c) Initial certification and recertification procedures for low mass emission units using the excepted methodologies under § 75.19 of this chapter. The owner or operator of a gas-fired or oil-fired unit using the low mass emissions excepted methodology under § 75.19 of this chapter shall meet the applicable general operating requirements of § 75.10 of this chapter, the applicable requirements of § 75.19 of this chapter, and the applicable certification requirements of § 96.71 of this chapter, except that the excepted methodology shall be deemed provisionally certified for use under the NO_X Budget Trading Program, as of the following dates:

(1) For units that are reporting on an annual basis under § 96.74(d);

(i) For a unit that has commences operation before its compliance deadline under § 96.71(b), from January 1 of the year following submission of the certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for the permitting authority review; or

(ii) For a unit that commences operation after its compliance deadline under § 96.71(b), the date of submission of the certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for permitting authority review, or

(2) For units that are reporting on a control period basis under § 96.74(b)(3)(ii) of this part:

(i) For a unit that commenced operation before its compliance deadline under § 96.71(b), where the certification application is submitted before May 1, from May 1 of the year of the submission of the certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for the permitting authority review; or

(ii) For a unit that commenced operation before its compliance deadline under § 96.71(b), where the certification application is submitted after May 1, from May 1 of the year following submission of the certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for the permitting authority review; or

(iii) For a unit that commences operation after its compliance deadline under § 96.71(b), where the unit commences operation before May 1, from May 1 of the year that the unit commenced operation, until the completion of the period for the permitting authority's review.

(iv) For a unit that has not operated after its compliance deadline under § 96.71(b), where the certification application is submitted after May 1, but before October 1st, from the date of submission of a certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for the permitting authority's review.

(d) Certification/recertification procedures for alternative monitoring systems. The NO_X authorized account representative representing the owner or operator of each unit applying to monitor using an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall apply for certification to the permitting authority prior to use of the system under the NO_X Trading Program. The NO_X authorized account representative shall apply for recertification following a replacement, modification or change according to the procedures in paragraph (b) of this section. The owner or operator of an alternative monitoring system shall comply with the notification and application requirements for certification according to the procedures specified in paragraph (b)(3) of this section and § 75.20(f) of this chapter .

§ 96.72 Out of control periods.

(a) Whenever any monitoring system fails to meet the quality assurance requirements of appendix B of part 75 of this chapter, data shall be substituted using the applicable procedures in subpart D, appendix D, or appendix E of part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any system or component should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 96.71 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the permitting authority will issue a notice of disapproval of the certification status of such system or component. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the permitting authority revokes prospectively the certification status of the system or component. The data measured and recorded by the system or component shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests. The owner or operator shall follow the initial certification or recertification procedures in § 96.71 for each disapproved system.

§ 96.73 Notifications.

The NO_X authorized account representative for a NO_X Budget unit shall submit written notice to the permitting authority and the Administrator in accordance with § 75.61 of this chapter, except that if the unit is not subject to an Acid Rain emissions limitation, the notification is only required to be sent to the permitting authority.

§ 96.74 Recordkeeping and reporting.

(a) *General provisions.* (1) The NO_X authorized account representative shall comply with all recordkeeping and reporting requirements in this section and with the requirements of § 96.10(e).

(2) If the NO_X authorized account representative for a NO_X Budget unit subject to an Acid Rain Emission limitation who signed and certified any submission that is made under subpart F or G of part 75 of this chapter and which includes data and information required under this subpart or subpart H of part 75 of this chapter is not the same person as the designated representative or the alternative designated representative for the unit under part 72 of this chapter, the submission must also be signed by the designated representative or the alternative designated representative.

(b) *Monitoring plans.* (1) The owner or operator of a unit subject to an Acid Rain emissions limitation shall comply with requirements of § 75.62 of this chapter, except that the monitoring plan shall also include all of the information required by subpart H of part 75 of this chapter.

(2) The owner or operator of a unit that is not subject to an Acid Rain emissions limitation shall comply with requirements of § 75.62 of this chapter, except that the monitoring plan is only required to include the information required by subpart H of part 75 of this chapter.

(c) *Certification applications.* The NO_X authorized account representative shall submit an application to the permitting authority within 45 days after completing all initial certification or recertification tests required under § 96.71 including the information required under subpart H of part 75 of this chapter.

(d) *Quarterly reports.* The NO_X authorized account representative shall submit quarterly reports, as follows:

(1) If a unit is subject to an Acid Rain emission limitation or if the owner or operator of the NO_X budget unit chooses to meet the annual reporting requirements of this subpart H, the NO_X authorized account representative shall submit a quarterly report for each calendar quarter beginning with:

(i) For units that elect to comply with the early reduction credit provisions under § 96.55 of this part, the calender quarter that includes the date of initial provisional certification under § 96.71(b)(3)(iii). Data shall be reported from the date and hour corresponding to the date and hour of provisional certification; or

(ii) For units commencing operation prior to May 1, 2002 that are not required to certify monitors by May 1, 2000 under § 96.70(b)(1), the earlier of the calender quarter that includes the date of initial provisional certification under § 96.71(b)(3)(iii) or, if the certification tests are not completed by May 1, 2002, the partial calender quarter from May 1, 2002 through June 30, 2002. Data shall be recorded and reported from the earlier of the date and hour corresponding to the date and hour of provisional certification or the first hour on May 1, 2002; or

(iii) For a unit that commences operation after May 1, 2002, the calendar quarter in which the unit commences operation, Data shall be reported from the date and hour corresponding to when the unit commenced operation.

(2) If a NO_X budget unit is not subject to an Acid Rain emission limitation, then the NO_X authorized account representative shall either:

(i) Meet all of the requirements of part 75 related to monitoring and reporting NO_X mass emissions during the entire year and meet the reporting deadlines specified in paragraph (d)(1) of this section; or

(ii) Submit quarterly reports only for the periods from the earlier of May 1 or the date and hour that the owner or operator successfully completes all of the recertification tests required under § 75.74(d)(3) through September 30 of each year in accordance with the provisions of § 75.74(b) of this chapter. The NO_X authorized account representative shall submit a quarterly report for each calendar quarter, beginning with:

(*A*) For units that elect to comply with the early reduction credit provisions under § 96.55, the calender quarter that includes the date of initial provisional certification under § 96.71(b)(3)(iii). Data shall be reported from the date and hour corresponding to the date and hour of provisional certification; or

(*B*) For units commencing operation prior to May 1, 2002 that are not required to certify monitors by May 1, 2000 under § 96.70(b)(1), the earlier of the calender quarter that includes the date of initial provisional certification under § 96.71(b)(3)(iii), or if the certification tests are not completed by May 1, 2002, the partial calender quarter from May 1, 2002 through June 30, 2002. Data shall be reported from the earlier of the date and hour corresponding to the date and hour of provisional certification or the first hour of May 1, 2002; or

(*C*) For units that commence operation after May 1, 2002 during the control period, the calender quarter in which the unit commences operation. Data shall be reported from the date and hour corresponding to when the unit commenced operation; or

(*D*) For units that commence operation after May 1, 2002 and before May 1 of the year in which the unit commences operation, the earlier of the calender quarter that includes the date of initial provisional certification under § 96.71(b)(3)(iii) or, if the certification tests are not completed by May 1 of the year in which the unit commences operation, May 1 of the year in which the unit commences operation. Data shall be reported from the earlier of the date and hour corresponding to the date and hour of provisional certification or the first hour of May 1 of the year after the unit commences operation.

(*E*) For units that commence operation after May 1, 2002 and after September 30 of the year in which the unit commences operation, the earlier of the calender quarter that includes the date of initial provisional certification under § 96.71(b)(3)(iii) or, if the certification tests are not completed by May 1 of the year after the unit commences operation, May 1 of the year after the unit commences operation. Data shall be reported from the earlier of the date and hour corresponding to the date and hour of provisional certification or the first hour of May 1 of the year after the unit commences operation.

(3) The NO_X authorized account representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in subpart H of part 75 of this chapter and § 75.64 of this chapter.

(i) For units subject to an Acid Rain Emissions limitation, quarterly reports shall include all of the data and information required in subpart H of part 75 of this chapter for each NO_X Budget unit (or group of units using a common stack) as well as information required in subpart G of part 75 of this chapter.

(ii) For units not subject to an Acid Rain Emissions limitation, quarterly reports are only required to include all of the data and information required in subpart H of part 75 of this chapter for each NO_X Budget unit (or group of units using a common stack).

(4) *Compliance certification.* The NO_X authorized account representative shall submit to the Administrator a compliance certification in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly

and fully monitored. The certification shall state that:

(i) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(ii) For a unit with add-on NO_X emission controls and for all hours where data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the monitoring plan and the substitute values do not systematically underestimate NO_X emissions; and

(iii) For a unit that is reporting on a control period basis under § 96.74(d) the NO_X emission rate and NO_X concentration values substituted for missing data under subpart D of part 75 of this chapter are calculated using only values from a control period and do not systematically underestimate NO_X emissions.

§ 96.75 Petitions.

(a) The NO_X authorized account representative of a NO_X Budget unit that is subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the Administrator requesting approval to apply an alternative to any requirement of this subpart.

(1) Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved by the Administrator, in consultation with the permitting authority.

(2) Notwithstanding paragraph (a)(1) of this section, if the petition requests approval to apply an alternative to a requirement concerning any additional CEMS required under the common stack provisions of § 75.72 of this chapter, the petition is governed by paragraph (b) of this section.

(b) The NO_X authorized account representative of a NO_X Budget unit that is not subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to any requirement of this subpart.

(1) The NO_X authorized account representative of a NO_X Budget unit that is subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to a requirement concerning any additional CEMS required under the common stack provisions of § 75.72 of this chapter or a NO_X concentration CEMS used under 75.71(a)(2) of this chapter.

(2) Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent the petition under paragraph (b) of this section is approved by both the permitting authority and the Administrator.

§ 96.76 Additional requirements to provide heat input data for allocations purposes.

(a) The owner or operator of a unit that elects to monitor and report NO_X Mass emissions using a NO_X concentration system and a flow system shall also monitor and report heat input at the unit level using the procedures set forth in part 75 of this chapter for any source located in a state developing source allocations based upon heat input.

(b) The owner or operator of a unit that monitor and report NO_X Mass emissions using a NO_X concentration system and a flow system shall also monitor and report heat input at the unit level using the procedures set forth in part 75 of this chapter for any source that is applying for early reduction credits under § 96.55.

Subpart I—Individual Unit Opt-ins

§ 96.80 Applicability.

A unit that is in the State, is not a NO_X Budget unit under § 96.4, vents all of its emissions to a stack, and is operating, may qualify, under this subpart, to become a NO_X Budget opt-in source. A unit that is a NO_X Budget unit, is covered by a retired unit exemption under § 96.5 that is in effect, or is not operating is not eligible to become a NO_X Budget opt-in source.

§ 96.81 General.

Except otherwise as provided in this part, a NO_X Budget opt-in source shall be treated as a NO_X Budget unit for purposes of applying subparts A through H of this part.

§ 96.82 NO_X authorized account representative.

A unit for which an application for a NO_X Budget opt-in permit is submitted and not denied or withdrawn, or a NO_X Budget opt-in source, located at the same source as one or more NO_X Budget units, shall have the same NO_X authorized account representative as such NO_X Budget units.

§ 96.83 Applying for NO_X Budget opt-in permit.

(a) *Applying for initial NO_X Budget opt-in permit.* In order to apply for an initial NO_X Budget opt-in permit, the NO_X authorized account representative of a unit qualified under § 96.80 may submit to the permitting authority at any time, except as provided under § 96.86(g):

(1) A complete NO_X Budget permit application under § 96.22;

(2) A monitoring plan submitted in accordance with subpart H of this part; and

(3) A complete account certificate of representation under § 96.13, if no NO_X authorized account representative has been previously designated for the unit.

(b) *Duty to reapply.* The NO_X authorized account representative of a NO_X Budget opt-in source shall submit a complete NO_X Budget permit application under § 96.22 to renew the NO_X Budget opt-in permit in accordance with § 96.21(c) and, if applicable, an updated monitoring plan in accordance with subpart H of this part.

§ 96.84 Opt-in process.

The permitting authority will issue or deny a NO_X Budget opt-in permit for a unit for which an initial application for a NO_X Budget opt-in permit under § 96.83 is submitted, in accordance with § 96.20 and the following:

(a) *Interim review of monitoring plan.* The permitting authority will determine, on an interim basis, the sufficiency of the monitoring plan accompanying the initial application for a NO_X Budget opt-in permit under § 96.83. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the NO_X emissions rate and heat input of the unit are monitored and reported in accordance with subpart H of this part. A determination of sufficiency shall not be construed as acceptance or approval of the unit's monitoring plan.

(b) If the permitting authority determines that the unit's monitoring plan is sufficient under paragraph (a) of this section and after completion of monitoring system certification under subpart H of this part, the NO_X emissions rate and the heat input of the unit shall be monitored and reported in accordance with subpart H of this part for one full control period during which monitoring system availability is not less than 90 percent and during which the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements. Solely for purposes of applying the requirements in the prior sentence, the unit shall be treated as a ‘‘NO_X Budget unit’’ prior to issuance of a NO_X Budget opt-in permit covering the unit.

(c) Based on the information monitored and reported under paragraph (b) of this section, the unit's baseline heat rate shall be calculated as the unit's total heat input (in mmBtu) for the control period and the unit's baseline NO_X emissions rate shall be calculated as the unit's total NO_X emissions (in lb) for the control period divided by the unit's baseline heat rate.

(d) After calculating the baseline heat input and the baseline NO_X emissions rate for the unit under paragraph (c) of this section, the permitting authority will serve a draft NO_X Budget opt-in permit on the NO_X authorized account representative of the unit.

(e) *Confirmation of intention to opt-in.* Within 20 days after the issuance of the draft NO_X Budget opt-in permit, the NO_X authorized account representative of the unit must submit to the permitting authority a confirmation of the intention to opt in the unit or a withdrawal of the application for a NO_X Budget opt-in permit under § 96.83. The permitting authority will treat the failure to make a timely submission as a withdrawal of the NO_X Budget opt-in permit application.

(f) *Issuance of draft NO_X Budget opt-in permit.* If the NO_X authorized account representative confirms the intention to opt-in the unit under paragraph (e) of this section, the permitting authority will issue the draft NO_X Budget opt-in permit in accordance with § 96.20.

(g) Notwithstanding paragraphs (a) through (f) of this section, if at any time before issuance of a draft NO_X Budget opt-in permit for the unit, the permitting authority determines that the unit does not qualify as a NO_X Budget opt-in source under § 96.80, the permitting authority will issue a draft denial of a NO_X Budget opt-in permit for the unit in accordance with § 96.20.

(h) *Withdrawal of application for NO_X Budget opt-in permit.* A NO_X authorized account representative of a unit may withdraw its application for a NO_X Budget opt-in permit under § 96.83 at any time prior to the issuance of the final NO_X Budget opt-in permit. Once the application for a NO_X Budget opt-in permit is withdrawn, a NO_X authorized account representative wanting to reapply must submit a new application for a NO_X Budget permit under § 96.83.

(i) *Effective date.* The effective date of the initial NO_X Budget opt-in permit shall be May 1 of the first control period starting after the issuance of the initial NO_X Budget opt-in permit by the permitting authority. The unit shall be a NO_X Budget opt-in source and a NO_X Budget unit as of the effective date of the initial NO_X Budget opt-in permit.

§ 96.85 NO_X Budget opt-in permit contents.

(a) Each NO_X Budget opt-in permit (including any draft or proposed NO_X Budget opt-in permit, if applicable) will contain all elements required for a complete NO_X Budget opt-in permit application under § 96.22 as approved or adjusted by the permitting authority.

(b) Each NO_X Budget opt-in permit is deemed to incorporate automatically the definitions of terms under § 96.2 and, upon recordation by the Administrator under subpart F, G, or I of this part, every allocation, transfer, or deduction of NO_X allowances to or from the compliance accounts of each NO_X Budget opt-in source covered by the NO_X Budget opt-in permit or the overdraft account of the NO_X Budget source where the NO_X Budget opt-in source is located.

§ 96.86 Withdrawal from NO_X Budget Trading Program.

(a) *Requesting withdrawal.* To withdraw from the NO_X Budget Trading Program, the NO_X authorized account representative of a NO_X Budget opt-in source shall submit to the permitting authority a request to withdraw effective as of a specified date prior to May 1 or after September 30. The submission shall be made no later than 90 days prior to the requested effective date of withdrawal.

(b) *Conditions for withdrawal.* Before a NO_X Budget opt-in source covered by a request under paragraph (a) of this section may withdraw from the NO_X Budget Trading Program and the NO_X Budget opt-in permit may be terminated under paragraph (e) of this section, the following conditions must be met:

(1) For the control period immediately before the withdrawal is to be effective, the NO_X authorized account representative must submit or must have submitted to the permitting authority an annual compliance certification report in accordance with § 96.30.

(2) If the NO_X Budget opt-in source has excess emissions for the control period immediately before the withdrawal is to be effective, the Administrator will deduct or has deducted from the NO_X Budget opt-in source's compliance account, or the overdraft account of the NO_X Budget source where the NO_X Budget opt-in source is located, the full amount required under § 96.54(d) for the control period.

(3) After the requirements for withdrawal under paragraphs (b)(1) and (2) of this section are met, the Administrator will deduct from the NO_X Budget opt-in source's compliance account, or the overdraft account of the NO_X Budget source where the NO_X Budget opt-in source is located, NO_X allowances equal in number to and allocated for the same or a prior control period as any NO_X allowances allocated to that source under § 96.88 for any control period for which the withdrawal is to be effective. The Administrator will close the NO_X Budget opt-in source's compliance account and will establish, and transfer any remaining allowances to, a new general account for the owners and operators of the NO_X Budget opt-in source. The NO_X authorized account representative for the NO_X Budget opt-in source shall become the NO_X authorized account representative for the general account.

(c) A NO_X Budget opt-in source that withdraws from the NO_X Budget Trading Program shall comply with all requirements under the NO_X Budget Trading Program concerning all years for which such NO_X Budget opt-in source was a NO_X Budget opt-in source, even if such requirements arise or must be complied with after the withdrawal takes effect.

(d) *Notification.* (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of NO_X allowances required), the permitting authority will issue a notification to the NO_X authorized account representative of the NO_X Budget opt-in source of the acceptance of the withdrawal of the NO_X Budget opt-in source as of a specified effective date that is after such requirements have been met and that is prior to May 1 or after September 30.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the permitting authority will issue a notification to the NO_X authorized account representative of the NO_X Budget opt-in source that the NO_X Budget opt-in source's request to withdraw is denied. If the NO_X Budget opt-in source's request to withdraw is denied, the NO_X Budget opt-in source shall remain subject to the requirements for a NO_X Budget opt-in source.

(e) *Permit amendment.* After the permitting authority issues a notification under paragraph (d)(1) of this section that the requirements for withdrawal have been met, the permitting authority will revise the NO_X Budget permit covering the NO_X Budget opt-in source to terminate the NO_X Budget opt-in permit as of the effective date specified under paragraph (d)(1) of this section. A NO_X Budget opt-in source shall continue to be a NO_X Budget opt-in source until the effective date of the termination.

(f) *Reapplication upon failure to meet conditions of withdrawal.* If the permitting authority denies the NO_X Budget opt-in source's request to withdraw, the NO_X authorized account representative may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(g) *Ability to return to the NO_X* Budget Trading Program. Once a NO_X Budget opt-in source withdraws from the NO_X Budget Trading Program and its NO_X Budget opt-in permit is terminated under this section, the NO_X authority account representative may not submit another application for a NO_X Budget opt-in permit under § 96.83 for the unit prior to the date that is 4 years after the date on which the terminated NO_X Budget opt-in permit became effective.

§ 96.87 Change in regulatory status.

(a) *Notification.* When a NO_X Budget opt-in source becomes a NO_X Budget unit under § 96.4, the NO_X authorized account representative shall notify in writing the permitting authority and the Administrator of such change in the NO_X Budget opt-in source's regulatory status, within 30 days of such change.

(b) *Permitting authority's and Administrator's action.* (1)(i) When the NO_X Budget opt-in source becomes a NO_X Budget unit under § 96.4, the permitting authority will revise the NO_X Budget opt-in source's NO_X Budget opt-in permit to meet the requirements of a NO_X Budget permit under § 96.23 as of an effective date that is the date on which such NO_X Budget opt-in source becomes a NO_X Budget unit under § 96.4.

(ii)(A) The Administrator will deduct from the compliance account for the NO_X Budget unit under paragraph (b)(1)(i) of this section, or the overdraft account of the NO_X Budget source where the unit is located, NO_X allowances equal in number to and allocated for the same or a prior control period as:

(*1*) Any NO_X allowances allocated to the NO_X Budget unit (as a NO_X Budget opt-in source) under § 96.88 for any control period after the last control period during which the unit's NO_X Budget opt-in permit was effective; and

(*2*) If the effective date of the NO_X Budget permit revision under paragraph (b)(1)(i) of this section is during a control period, the NO_X allowances allocated to the NO_X Budget unit (as a NO_X Budget opt-in source) under § 96.88 for the control period multiplied by the ratio of the number of days, in the control period, starting with the effective date of the permit revision under paragraph (b)(1)(i) of this section, divided by the total number of days in the control period.

(B) The NO_X authorized account representative shall ensure that the compliance account of the NO_X Budget unit under paragraph (b)(1)(i) of this section, or the overdraft account of the NO_X Budget source where the unit is located, includes the NO_X allowances necessary for completion of the deduction under paragraph (b)(1)(ii)(A) of this section. If the compliance account or overdraft account does not contain sufficient NO_X allowances, the Administrator will deduct the required number of NO_X allowances, regardless of the control period for which they were allocated, whenever NO_X allowances are recorded in either account.

(iii)(A) For every control period during which the NO_X Budget permit revised under paragraph (b)(1)(i) of this section is effective, the NO_X Budget unit under paragraph (b)(1)(i) of this section will be treated, solely for purposes of NO_X allowance allocations under § 96.42, as a unit that commenced operation on the effective date of the NO_X Budget permit revision under paragraph (b)(1)(i) of this section and will be allocated NO_X allowances under § 96.42.

(B) Notwithstanding paragraph (b)(1)(iii)(A) of this section, if the effective date of the NO_X Budget permit revision under paragraph (b)(1)(i) of this section is during a control period, the following number of NO_X allowances will be allocated to the NO_X Budget unit under paragraph (b)(1)(i) of this section under § 96.42 for the control period: the number of NO_X allowances otherwise allocated to the NO_X Budget unit under § 96.42 for the control period multiplied by the ratio of the number of days, in the control period, starting with the effective date of the permit revision under paragraph (b)(1)(i) of this section, divided by the total number of days in the control period.

(2)(i) When the NO_X authorized account representative of a NO_X Budget opt-in source does not renew its NO_X Budget opt-in permit under § 96.83(b), the Administrator will deduct from the NO_X Budget opt-in unit's compliance account, or the overdraft account of the NO_X Budget source where the NO_X Budget opt-in source is located, NO_X allowances equal in number to and allocated for the same or a prior control period as any NO_X allowances allocated to the NO_X Budget opt-in source under § 96.88 for any control period after the last control period for which the NO_X Budget opt-in permit is effective. The NO_X authorized account representative shall ensure that the NO_X Budget opt-in source's compliance account or the overdraft account of the NO_X Budget source where the NO_X Budget opt-in source is located includes the NO_X allowances necessary for completion of such deduction. If the compliance account or overdraft account does not contain sufficient NO_X allowances, the Administrator will deduct the required number of NO_X allowances, regardless of the control period for which they were allocated, whenever NO_X allowances are recorded in either account.

(ii) After the deduction under paragraph (b)(2)(i) of this section is completed, the Administrator will close the NO_X Budget opt-in source's compliance account. If any NO_X allowances remain in the compliance account after completion of such deduction and any deduction under § 96.54, the Administrator will close the NO_X Budget opt-in source's compliance account and will establish, and transfer any remaining allowances to, a new general account for the owners and operators of the NO_X Budget opt-in source. The NO_X authorized account representative for the NO_X Budget opt-in source shall become the NO_X authorized account representative for the general account.

§ 96.88 NO_X allowance allocations to opt-in units.

(a) *NO_X allowance allocation.* (1) By December 31 immediately before the first control period for which the NO_X Budget opt-in permit is effective, the permitting authority will allocate NO_X allowances to the NO_X Budget opt-in source and submit to the Administrator the allocation for the control period in accordance with paragraph (b) of this section.

(2) By no later than December 31, after the first control period for which the NO_X Budget opt-in permit is in effect, and December 31 of each year thereafter, the permitting authority will allocate NO_X allowances to the NO_X Budget opt-in source, and submit to the Administrator allocations for the next control period, in accordance with paragraph (b) of this section.

(b) For each control period for which the NO_X Budget opt-in source has an approved NO_X Budget opt-in permit, the NO_X Budget opt-in source will be allocated NO_X allowances in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating NO_X allowance allocations will be the lesser of:

(i) The NO_X Budget opt-in source's baseline heat input determined pursuant to § 96.84(c); or

(ii) The NO_X Budget opt-in source's heat input, as determined in accordance with subpart H of this part, for the control period in the year prior to the year of the control period for which the NO_X allocations are being calculated.

(2) The permitting authority will allocate NO_X allowances to the NO_X Budget opt-in source in an amount equaling the heat input (in mmBtu) determined under paragraph (b)(1) of this section multiplied by the lesser of:

(i) The NO_X Budget opt-in source's baseline NO_X emissions rate (in lb/mmBtu) determined pursuant to § 96.84(c); or

(ii) The most stringent State or Federal NO_X emissions limitation applicable to the NO_X Budget opt-in source during the control period.

Subpart J—Mobile and Area Sources [Reserved]

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