ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 52, 72, 78, and 97

[EPA–HQ–OAR–2009–0491; FRL–9174–9]

RIN 2060–AP50

Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to limit the interstate transport of emissions of nitrogen oxides (NO_X) and sulfur dioxide (SO_2). In this action, EPA is proposing to both identify and limit emissions within 32 states in the eastern United States that affect the ability of downwind states to attain and maintain compliance with the 1997 and 2006 fine particulate matter ($PM_{2.5}$) national ambient air quality standards (NAAQS) and the 1997 ozone NAAQS. EPA is proposing to limit these emissions through Federal Implementation Plans (FIPs) that regulate electric generating units (EGUs) in the 32 states. This action will substantially reduce the impact of transported emissions on downwind states. In conjunction with other federal and state actions, it helps assure that all but a handful of areas in the eastern part of the country will be in compliance with the current ozone and $PM_{2.5}$ NAAQS by 2014 or earlier. To the extent the proposed FIPs do not fully address all significant transport, EPA is committed to assuring that any additional reductions needed are addressed quickly. EPA takes comments on ways this proposal could achieve additional NO_X reductions and additional actions including other rulemakings that EPA could undertake to achieve any additional reductions needed.

DATES: *Comments.* Comments must be received on or before October 1, 2010.

Public Hearing: Three public hearings will be held before the end of the comment period. The dates, times and locations will be announced separately. Please refer to **SUPPLEMENTARY INFORMATION** for additional information on the comment period and the public hearings.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2009–0491 by one of the following methods:

- *http://www.regulations.gov.* Follow the online instructions for submitting comments. Attention Docket ID No. EPA–HQ–OAR–2009–0491.
- *E-mail: a-and-r-docket@epa.gov.* Attention Docket ID No. EPA–HQ–OAR–2009–0491.
- *Fax:* (202) 566–9744. Attention Docket ID No. EPA–HQ–OAR–2009–0491.
- *Mail:* EPA Docket Center, EPA West (Air Docket), Attention Docket ID No. EPA–HQ–OAR–2009–0491, U.S. Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Avenue, NW., Washington, DC 20460. Please include 2 copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attn: Desk Officer for EPA, 725 17th Street, NW., Washington, DC 20503.
- *Hand Delivery:* U.S. Environmental Protection Agency, EPA West (Air Docket), 1301 Constitution Avenue, Northwest, Room 3334, Washington, DC 20004, Attention Docket ID No. EPA–HQ–OAR–2009–0491. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions. Direct your comments to Docket ID No. EPA–HQ–OAR–2009–0491. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov*, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, avoid any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

Docket. All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Air and Radiation Docket and Information Center, EPA/DC, EPA West Building, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Tim Smith, Air Quality Policy Division, Office of Air Quality Planning and Standards (C539–04), Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number: (919) 541–4718; fax number: (919) 541–0824; e-mail address: *smith.tim@epa.gov.* For legal questions, please contact Ms. Sonja Rodman, U.S. EPA, Office of General Counsel, Mail Code 2344A, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, telephone (202) 564–4079; e-mail address *rodman.sonja@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Preamble Glossary of Terms and Abbreviations

The following are abbreviations of terms used in the preamble.

ARP Acid Rain Program
BART Best Available Retrofit Technology
BACT Best Available Control Technology
CAA or Act Clean Air Act
CAIR Clean Air Interstate Rule
CBI Confidential Business Information
CFR Code of Federal Regulations
EGU Electric Generating Unit
FERC Federal Energy Regulatory Commission
FGD Flue Gas Desulfurization
FIP Federal Implementation Plan
FR Federal Register
EPA U.S. Environmental Protection Agency
GHG Greenhouse Gas
Hg Mercury
IPM Integrated Planning Model
lb/mmbtu Pounds Per Million British Thermal Unit
$\mu g/m^3$ Micrograms Per Cubic Meter

NAAQS National Ambient Air Quality Standards
NO_X Nitrogen Oxides
NSPS New Source Performance Standard
OTAG Ozone Transport Assessment Group
PUC Public Utility Commission
SNCR Selective Non-catalytic Reduction
SCR Selective Catalytic Reduction
SIP State Implementation Plan
$PM_{2.5}$ Fine Particulate Matter, Less Than 2.5 Micrometers
PM_{10} Fine and Coarse Particulate Matter, Less Than 10 Micrometers
PM Particulate Matter
RIA Regulatory Impact Analysis
SO_2 Sulfur Dioxide
SO_X Sulfur Oxides, Including Sulfur Dioxide (SO_2) and Sulfur Trioxide (SO_3)
TIP Tribal Implementation Plan tpy Tons Per Year
TSD Technical Support Document

II. General Information

A. Does this action apply to me?

This rule affects EGUs, and regulates the following groups:

Industry group	NAICS [a]
Utilities (electric, natural gas, other systems).	2211, 2212, 2213

[a] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that EPA is aware of that could potentially be regulated. Other types of entities not listed in the table could also be regulated. To determine whether your facility would be regulated by the proposed rule, you should carefully examine the applicability criteria in proposed §§ 97.404, 97.504, 97,604, and 97.704.

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this proposal will also be available on the World Wide Web. Following signature by the EPA Administrator, a copy of this action will be posted on the transport rule Web site *http://www.epa.gov/airtransport.*

C. What should I consider as I prepare my comments for EPA?

1. *Submitting CBI.* Do not submit this information to EPA through *http://www.regulations.gov* or e-mail. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404–02), U.S. EPA, Research Triangle Park, NC 27711, Attention Docket ID No. EPA–HQ–OAR–2009–0491.

2. *Tips for preparing your comments.* When submitting comments, remember to:

• Identify the rulemaking by docket number and other identifying information (subject heading, **Federal Register** date and page number).

• Follow directions—The agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

• Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

• Describe any assumptions and provide any technical information and/or data that you used.

• If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

• Provide specific examples to illustrate your concerns, and suggest alternatives.

• Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

• Make sure to submit your comments by the comment period deadline identified.

D. How can I find information about the public hearings?

The EPA will hold three public hearings on this proposal. The dates, times and locations of the pubic hearings will be announced separately. Oral testimony will be limited to 5 minutes per commenter. The EPA encourages commenters to provide written versions of their oral testimonies either electronically or in paper copy. Verbatim transcripts and written statements will be included in the rulemaking docket. If you would like to present oral testimony at one of the hearings, please notify Ms. Pamela S. Long, Air Quality Policy Division (C504–03), U.S. EPA, Research Triangle Park, NC 27711, telephone number (919) 541–0641; e-mail: *long.pam@epa.gov.* Persons interested in presenting oral testimony should notify Ms. Long at least 2 days in advance of the public hearings. For updates and additional information on the public hearings, please check EPA's website for this rulemaking, *http://www.epa.gov/airtransport.* The public hearings will provide interested parties the opportunity to present data, views, or arguments concerning the proposed rule. The EPA officials may ask clarifying questions during the oral presentations, but will not respond to the presentations or comments at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as any oral comments and supporting information presented at the public hearings.

E. How is this Preamble Organized?

III. Summary of Proposed Rule and Background

A. Summary of Proposed Rule

CAA section 110(a)(2)(D)(i)(I) requires states to prohibit emissions that contribute significantly to nonattainment in, or interfere with maintenance by, any other state with respect to any primary or secondary NAAQS. In this notice, EPA proposes to find that emissions of SO_2 and NO_X in 32 eastern states contribute significantly to nonattainment or interfere with maintenance in one or more downwind states with respect to one or more of three air quality standards—the annual average $PM_{2.5}$ NAAQS promulgated in 1997, the 24-hour average $PM_{2.5}$ NAAQS promulgated in 2006, and the ozone NAAQS promulgated in 1997.[1] These emissions are transported downwind either as SO_2 and NO_X or, after transformation in the atmosphere, as fine particles or ozone. This notice identifies emission reduction responsibilities of upwind states, and also proposes enforceable FIPs to achieve the required emissions reductions in each state through cost-effective and flexible requirements for power plants. Each state will have the option of replacing these Federal rules with state rules to achieve the required amount of emissions reductions from sources selected by the state.

With respect to the annual average $PM_{2.5}$ NAAQS, this proposal finds that 24 eastern states have SO_2 and NO_X emission reduction responsibilities, and quantifies each state's full emission reduction responsibility under section 110(a)(2)(D)(i)(I). With respect to the 24-hour average $PM_{2.5}$ NAAQS, this proposal finds that 25 eastern states have emission reduction responsibilities. The proposed reductions will at least partly eliminate, and subject to further analysis may fully eliminate, these states' significant contribution and interference with maintenance for purposes of the 24-hour average $PM_{2.5}$ standard. In all, emissions reductions related to interstate transport

[1] In the context of the jurisdictions covered by this proposed rule, EPA uses the term "states" to include the District of Columbia.

of fine particles would be required in 28 states.

With respect to the 1997 ozone NAAQS, this proposal requires emissions reductions in 26 states. For 16 of these states, we propose that the required reductions represent their full significant contribution and interference with maintenance for the ozone NAAQS. For an additional 10 states, the required NO_X reductions are needed for these states to make measurable progress towards eliminating their significant contribution and interference with maintenance. EPA has begun to conduct additional information gathering and analysis to determine the extent to which further reductions from these states may be needed to fully eliminate significant contribution and interference with maintenance with the 1997 ozone NAAQS.

This proposed rule would achieve substantial near-term emissions reductions from the power sector. EPA projects that with the proposed rule, EGU SO_2 emissions would be 5.0 million tons lower, annual NO_X emissions would be 700,000 tons lower, and ozone season NO_X emissions would be 100,000 tons lower in 2012, compared to baseline 2012 projections in the proposed covered states. Further, EGU SO_2 emissions would be 4.6 million tons lower, annual NO_X emissions would be 700,000 tons lower, and ozone season NO_X emissions would be 100,000 tons lower in 2014, compared to baseline 2014 projections (which will have dropped from 2012 due to other federal and state requirements, thereby lowering the 2014 baseline). *See* Table III.A–2 for projected EGU emissions with the proposed rule compared to baseline, and Table III.A–3 for projected EGU emissions with the proposed rule compared to 2005 actual emissions. The reductions obtained through the Transport Rule FIPs will help all but a very few areas in the eastern part of the country come into attainment with the 1997 $PM_{2.5}$ and ozone standards and take major strides toward helping states address nonattainment with the 2006 24-hour average $PM_{2.5}$ standard. *See* Table III.A–1 for proposed list of covered states.

EPA is committed to fulfilling its responsibility to ensure that downwind states receive the relief from upwind emissions guaranteed under CAA section 110(a)(2)(D) For the 24-hour $PM_{2.5}$ standard, EPA's air quality modeling shows that in the areas with continuing non-attainment or maintenance problems, the remaining exceedances occur almost entirely in the winter months. The relative importance of particle species such as sulfate and nitrate, is quite different between summer and winter. EPA is moving ahead before the final rule is published to determine the extent to which this wintertime problem is caused by emissions transported from upwind states. Further study of the 24-hour $PM_{2.5}$ results could lead to a number of possible outcomes; EPA cannot judge the relative likelihood of these outcomes at this time. To the extent possible, EPA plans to finalize this rule with a full determination of, and remedy for, significant contribution and interference with maintenance for the 24-hour $PM_{2.5}$ standard. To that end, EPA is expeditiously proceeding with examination of the residual wintertime problem. (See full discussion in section IV.D.)

In the case of ozone, EPA must determine whether further NO_X reductions are warranted in certain upwind states that affect two or three areas with relatively persistent ozone air quality problems. To support a full significant contribution determination for these states, EPA is expeditiously conducting further analysis of NO_X control costs, emissions reductions, air quality impacts, and the nature of the residual air quality issues. EPA's current information indicates that considering NO_X reductions beyond the cost per ton levels proposed in this rule will require analysis of reductions from source categories other than EGUs, as well as from EGUs. EPA believes that developing supplemental information to consider NO_X sources beyond EGUs would substantially delay publication of a final rule beyond the anticipated publication of spring 2011. EPA does not believe that this effort should delay the reductions and large health benefits associated with this proposed rule. Thus, EPA intends to proceed with additional rulemaking to address fully the residual significant contribution to nonattainment and interference with maintenance with the ozone standard as quickly as possible. (See full discussion in section IV.D.)

This proposed rule is the first of several EPA rules to be issued over the next 2 years that will yield substantial health and environmental benefits for the public through regulation of power plants. Fossil-fuel-fired power plants contribute a large and substantial fraction of the emissions of several key air pollutants, and the agency has statutory or judicial obligations to make several regulatory determinations on power plant emissions. The Administrator in January established improved air quality as an Agency priority and announced plans to promote a cleaner and more efficient power sector and have strong but achievable reduction goals for SO_2, NO_X, mercury, and other air toxics."

In addition to this rule, other anticipated actions include a section 112(d) rule for electric utilities to be proposed by March 2011, potential rules to address pollution transport under revised NAAQS, revisions to new source performance standards for coal and oil-fired utility electric generating units, and best available retrofit technology (BART) and regional haze program requirements to protect visibility. These actions, and their relationship to this rule, are discussed further in section III.E.

Ongoing reviews of the ozone and $PM_{2.5}$ NAAQS could result in revised NAAQS. To address any new NAAQS, EPA would propose interstate transport determinations in future notices. Such proposals could require greater emissions reductions from states covered by this proposal and/or require reductions from states not covered by this proposal. In addition, while this action proposes to require reductions from the power sector only, it is possible that reductions from other source categories could be needed to address interstate transport requirements related to any new NAAQS.

With this proposal, EPA is also responding to the remand of the CAIR by the Court in 2008. CAIR, promulgated May 12, 2005 (70 FR 25162) requires 28 states and the District of Columbia to adopt and submit revisions to their State Implementation Plans (SIPs) to eliminate SO_2 and NO_X emissions that contribute significantly to downwind nonattainment of the $PM_{2.5}$ and ozone NAAQS promulgated in July 1997. The CAIR FIPs, promulgated April 26, 2006 (71 FR 25328), regulate EGUs in the covered states and achieve the emissions reductions requirements established by CAIR until states have approved SIPs to achieve the reductions. In July 2008, the DC Circuit Court found CAIR and the CAIR FIPs unlawful. *North Carolina* v. *EPA*, 531 F.3d 896 (DC Cir. 2008). The Court's original decision vacated CAIR. *Id.* at 929–30. However, the Court subsequently remanded CAIR to EPA without vacatur because it found that "allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values covered by CAIR." *North Carolina* v. *EPA*, 550 F.3d 1176, 1178 (DC Cir. 2008). The CAIR requirements are correctly in place and the CAIR's regional control programs are operating while EPA develops replacement rules in response to the remand.

As described more fully in the remainder of this preamble, the approaches used in this proposed rule to measure and address each state's significant contribution to downwind nonattainment and interference with maintenance are guided by and consistent with the Court's opinion in *North Carolina* v. *EPA* and address the flaws in CAIR identified by the Court therein. Among other things, the proposal relies on detailed, bottom-up scientific and technical analyses, introduces a state-specific methodology for identifying significant contribution to nonattainment and interference with maintenance, and proposes remedy options to ensure that all necessary reductions are achieved in the covered states.

In this action, EPA proposes to both identify and address emissions within states in the eastern United States that significantly contribute to nonattainment or interfere with maintenance by other downwind states. As discussed in sections III and VII in this preamble and described in greater detail in two separate **Federal Register** notices published on April 25, 2005 (70 FR 21147) and June 9, 2010 (75 FR 32673), EPA has determined, or proposed to determine, that the 32 states covered by this proposal either have not submitted SIPs adequate to meet the requirements of 110(a)(2)(D)(i)(I) with respect to the 1997 and 2006 $PM_{2.5}$ NAAQS and the 1997 ozone NAAQS, or that the SIP provisions currently in place are not adequate to meet those requirements.

As described in section IV in this preamble, EPA is proposing a state-specific methodology to identify specific reductions that states in the eastern United States must make to satisfy the CAA section 110(a)(2)(D)(i)(I) prohibition on emissions that significantly contribute to nonattainment or interfere with maintenance in a downwind state. The proposed methodology uses state-specific inputs and focuses on the emissions reductions available in each individual state to address the Court's concern that the approach used in CAIR (which identified a single level of emissions achievable by the application of highly cost effective controls in the region) was insufficiently state specific. The proposed methodology uses air quality analysis to determine whether a state's contribution to downwind air quality problems is above specific thresholds. If a state's contribution does not exceed those thresholds, its contribution is found to be insignificant and it is no longer considered in the analysis. If a state's contribution exceeds those thresholds, EPA takes a second step that uses a multi-factor analysis that takes into account both air quality and cost considerations to identify the portion of a state's contribution that is significant or that interferes with maintenance. Section 110(a)(2)(D) requires states to eliminate the emissions that constitute this "significant contribution" and "interference with maintenance."

This proposed methodology for determining upwind state emission reduction responsibility is designed to be applicable to current and potential future ozone and $PM_{2.5}$ NAAQS. It is based on cost and air quality considerations that are common to any NAAQS, but also calls for evaluation of facts specific to a particular NAAQS. As a result, application of the methodology to a revised, more stringent NAAQS might lead to a determination that greater reductions in transported pollution from upwind states are reasonable than for a current, less stringent NAAQS.

To facilitate implementation of the requirement that significant contribution and interference with maintenance be eliminated, EPA developed state emissions budgets. By tying these budgets directly to EPA's quantification of each individual state's significant contribution and interference with maintenance, EPA directly linked the budgets to the mandate in section 110(a)(2)(D)(i)(I), and thus addressed the Court's concerns about the development of budgets for the CAIR. EPA also addressed these concerns by completely eschewing any consideration or reliance on Fuel Adjustment Factors and the existing allocation of Title IV allowances.

These new emissions budgets are based on the Agency's state-by-state analysis of each upwind state's significant contribution to nonattainment and interference with maintenance downwind. A state's emissions budget is the quantity of emissions that would remain after elimination of the part of significant contribution and interference with maintenance that EPA has identified in an average year (*i.e.*, before accounting for the inherent variability in power system operations).[2] EPA proposes SO_2 and NO_X budgets for each state covered for the 24-hour and/or annual average $PM_{2.5}$ NAAQS. EPA proposes an ozone season [3] NO_X budget for each state covered for the ozone NAAQS.

EPA recognizes that baseline emissions from a state can be affected by changing weather patterns, demand growth, or disruptions in electricity supply from other units. As a result, emissions could vary from year to year in a state where covered sources have installed all controls and taken all measures necessary to eliminate the state's significant contribution and interference with maintenance. As described in detail in section IV of this preamble, EPA proposes to account for the inherent variability in power system operations through "assurance provisions" based on state variability limits which extend above the state emissions budgets. *See* section V for a detailed discussion of the assurance provisions. The small amount of variability allowed takes into account the inherent variability in baseline emissions. Section IV in this preamble describes the proposed approach to significant contribution and interference with maintenance and the state emissions budgets and variability limits in detail.

EPA is also proposing FIPs to immediately implement the emission reduction requirements identified and quantified by EPA in this action. For some covered states, these FIPs will completely satisfy the emissions reductions requirements of 110(a)(2)(D)(i)(I) with respect to the 1997 and 2006 $PM_{2.5}$ NAAQS and the 1997 ozone NAAQS. The exception is for the 10 eastern states for which EPA has not completely quantified the total significant contribution or interference with maintenance with respect to the 1997 ozone NAAQS and the 15 states for which EPA has not completely quantified total significant contribution or interference with maintenance with respect to the 2006 $PM_{2.5}$ NAAQS in which case the FIPs would achieve measurable progress towards implementing that requirement.

The emissions reductions requirements (*i.e.*, the "remedy") that EPA is proposing to include in the FIPs responds to the Court's concerns that EPA had not shown that the CAIR reduction requirements would get all

[2] For the 10 states discussed above for which EPA has only quantified a minimum amount of emissions reductions needed to make measurable progress towards eliminating their significant contribution and interference with maintenance with respect to the 1997 8-hour ozone NAAQS, the emissions budget is the emissions that will remain after removal of those emissions.

[3] Consistent with the approach taken by the Ozone Transport Assessment Group (OTAG), the NO_X SIP call, and the CAIR, we propose to define the ozone season, for purposes of emissions reductions requirements in this rule, as May through September. We recognize that this ozone season for regulatory requirements differs from the official state-specific monitoring season.

necessary reductions "in the state" as required by section 110(a)(2)(D)(i)(I). The proposed FIPs include assurance provisions specifically designed to ensure that no state's emissions are allowed to exceed that specific state's budget plus the variability limit.

The proposed FIPs would regulate EGUs in the 32 covered states. EPA is proposing to regulate these sources through a program that uses state-specific budgets and allows intrastate and limited interstate trading. EPA is also taking comment on two alternative regulatory options. All options would achieve the emissions reductions necessary to address the emissions transport requirements in section 110(a)(2)(D)(i)(I) of the CAA.

The option EPA is proposing for the FIPs ("State Budgets/Limited Trading") would use state-specific emissions budgets and allow for intrastate and limited interstate trading. This approach would assure environmental results while providing some limited flexibility to covered sources. The approach would also facilitate the transition from CAIR to the Transport Rule for implementing agencies and covered sources.

The first alternative remedy option for which EPA requests comment would use state-specific emissions budgets and allow intrastate trading, but prohibit interstate trading. The second alternative remedy option, for which EPA also requests comment, would use state-specific budgets and emissions rate limits. See section V for further discussion of the remedy options.

The proposed remedy option and the first alternative, both of which are cap-and-trade approaches, would use new allowance allocations developed on a different basis from CAIR. Allowance allocations, like the state budgets described previously, would be developed based on the methodology used by EPA to quantify each state's significant contribution and interference with maintenance. *See* section IV for the proposed state budget approach and section V for proposed allowance allocation approaches.

In this action, EPA proposes to require reductions in SO_2 and NO_X emissions in the following 25 jurisdictions that contribute significantly to nonattainment in, or interfere with maintenance by, a downwind area with respect to the 24-hour $PM_{2.5}$ NAAQS promulgated in September 2006: Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin.

EPA proposes to require reductions in SO_2 and NO_X emissions in the following 24 jurisdictions that contribute significantly to nonattainment in, or interfere with maintenance by, a downwind area with respect to the annual $PM_{2.5}$ NAAQS promulgated in July 1997: Alabama, Delaware, District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

EPA also proposes to require reductions in ozone season NO_X emissions in the following 26 jurisdictions that contribute significantly to nonattainment in, or interfere with maintenance by, a downwind area with respect to the 1997 ozone NAAQS promulgated in July 1997: Alabama, Arkansas, Connecticut, Delaware, District of Columbia, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maryland, Michigan, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West Virginia.

As discussed previously, EPA also is proposing FIPs to directly regulate EGU SO_2 and/or NO_X emissions in the 32 covered states. The proposed FIPs would require the 28 jurisdictions covered for purposes of the 24-hour and/or annual $PM_{2.5}$ NAAQS to reduce SO_2 and NO_X emissions by specified amounts. The proposed FIPs would require the 26 states covered for purposes of the ozone NAAQS to reduce ozone season NO_X emissions by specified amounts.

In response to the Court's opinion in *North Carolina* v. *EPA*, EPA has coordinated the compliance deadlines for upwind states to eliminate emissions that significantly contribute to or interfere with maintenance in downwind areas with the NAAQS attainment deadlines that apply to the downwind nonattainment and maintenance areas. EPA proposes to require that all significant contribution to nonattainment and interference with maintenance identified in this action with respect to the $PM_{2.5}$ NAAQS be eliminated by 2014 and proposes an initial phase of reductions starting in 2012 (covering 2012 and 2013) to ensure that the reductions are made as expeditiously as practicable and that no backsliding from current emissions levels occurs when the requirements of the CAIR are eliminated. Sources will be required to comply by January 1, 2012 and January 1, 2014 for the first and second phases, respectively. With respect to the 1997 ozone NAAQS, EPA proposes to require an initial phase of NO_X reductions starting in 2012 to ensure that reductions are made as expeditiously as practicable. Sources will be required to comply by May 1, 2012 and May 1, 2014 for the first and second phases, respectively. EPA has determined, that for many states, these reductions will be sufficient to eliminate their significant contribution with respect to the 1997 ozone NAAQS. EPA intends to issue a subsequent proposal that would require all significant contribution and interference with maintenance be eliminated by a future date for the 1997 ozone NAAQS. *See* Table III.A–1 for proposed lists of covered state.

TABLE III.A–1—LISTS OF COVERED STATES FOR $PM_{2.5}$ AND 8-HOUR OZONE NAAQS

State	Covered for 24-hour and/or annual $PM_{2.5}$	Covered for 8-hour ozone
	Required to reduce SO_2 and NO_X	Required to reduce ozone Season NO_X
Alabama	X	X
Arkansas	....	X
Connecticut	X	X
Delaware	X	X
District of Columbia	X	X
Florida	X	X

TABLE III.A–1—LISTS OF COVERED STATES FOR $PM_{2.5}$ AND 8-HOUR OZONE NAAQS—Continued

State	Covered for 24-hour and/or annual $PM_{2.5}$ — Required to reduce SO_2 and NO_X	Covered for 8-hour ozone — Required to reduce ozone Season NO_X
Georgia	X	X
Illinois	X	X
Indiana	X	X
Iowa	X	
Kansas	X	X
Kentucky	X	X
Louisiana	X	X
Maryland	X	X
Massachusetts	X	
Michigan	X	X
Minnesota	X	
Mississippi		X
Missouri	X	
Nebraska	X	
New Jersey	X	X
New York	X	X
North Carolina	X	X
Ohio	X	X
Oklahoma		X
Pennsylvania	X	X
South Carolina	X	X
Tennessee	X	X
Texas		X
Virginia	X	X
West Virginia	X	X
Wisconsin	X	
Totals	28	26

As discussed previously, EPA is proposing new SO_2 and/or NO_X emissions budgets for each covered state. The budgets are based on the EPA's state-by-state analysis of each upwind state's significant contribution to nonattainment and interference with maintenance downwind, before accounting for the inherent variability in power system operations.

As discussed in detail in section IV, the proposed approach to significant contribution to nonattainment and interference with maintenance would group the 28 states covered for the 24-hour and/or annual $PM_{2.5}$ NAAQS in two tiers reflecting the stringency of SO_2 reductions required to eliminate that state's significant contribution to nonattainment and interference with maintenance. There would be a stringent SO_2 tier comprising 15 states ("group 1") and a moderate SO_2 tier comprising 13 states ("group 2"), with uniform stringency within each tier.[4] For these same 28 states, there would be one annual NO_X tier with uniform stringency of NO_X reductions across all 28 states. Similarly, for the 26 states covered for the ozone NAAQS there would be one ozone season NO_X tier with uniform stringency across all 26 states.

The proposed stringent SO_2 tier ("group 1") would include Georgia, Illinois, Indiana, Iowa, Kentucky, Michigan, Missouri, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin. The proposed moderate SO_2 tier ("group 2") would include Alabama, Connecticut, Delaware, District of Columbia, Florida, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Nebraska, New Jersey, and South Carolina.

As discussed previously, EPA proposes to require an initial phase of reductions starting in 2012 (covering 2012 and 2013) requiring SO_2 and NO_X reductions in the 28 states covered for 24-hour and/or annual $PM_{2.5}$ NAAQS. A second phase of reductions would be due in 2014, covering 2014 and thereafter. As described later, for certain states the 2014 reduction requirements would be more stringent, and for certain states would remain at the same level as the 2012 requirements.

For the 15 states in the stringent SO_2 tier ("group 1"), the 2014 phase would substantially increase the SO_2 reduction requirements (*i.e.*, these states would have smaller SO_2 emissions budgets starting in 2014), reflecting the greater reductions needed to eliminate the portion of significant contribution and interference with maintenance that EPA has identified in this proposal from these states with respect to the 24-hour $PM_{2.5}$ NAAQS. For the 13 states in the moderate SO_2 tier ("group 2"), the 2014 SO_2 emissions budgets would remain the same as the 2012 SO_2 budgets for these states.

The 2014 annual NO_X emissions budgets for all 28 states covered for the 24-hour and/or annual $PM_{2.5}$ NAAQS would remain the same as the 2012 annual NO_X budgets.

With respect to the ozone NAAQS, EPA is proposing a single phase of reductions which begins in 2012. Thus, the rule does not call for any adjustment to be made to the 2012 ozone season NO_X budgets for the 26 states covered for the ozone NAAQS. EPA intends to issue a subsequent proposal that would, among other things, address whether an additional phase of NO_X reductions is necessary to address all significant

[4] With regard to interstate trading, the two SO_2 stringency tiers would lead to two exclusive SO_2 trading groups. That is, states in SO_2 group 1 could not trade with states in SO_2 group 2.

contribution and interference with maintenance with respect to the 1997 ozone NAAQS. While this proposal assures downwind states that they will receive relief from upwind reductions that will help them achieve the NAAQS, EPA is committed to fulfilling its obligation to assure the downwind states that they receive the full relief they are entitled to under section 110(a)(2)(D). The Agency intends to quickly address any remaining significant contribution to nonattainment and interference with maintenance in a subsequent action that will also address a new more stringent ozone standard that is expected to be established by EPA later in 2010.

Tables III.A–2 and III.A–3 show projected Transport Rule emissions reductions for EGUs in all states that EPA proposes to cover.

TABLE III.A–2—PROJECTED SO_2 AND NO_X EGU EMISSIONS IN COVERED STATES WITH THE TRANSPORT RULE [5] COMPARED TO BASE CASE [6] WITHOUT TRANSPORT RULE OR CAIR

[Million tons]

	2012 Base case emissions	2012 Transport rule emissions	2012 Emissions reductions	2014 Base case emissions	2014 Transport rule emissions	2014 Emissions reductions
SO_2	8.4	3.4	5.0	7.2	2.6	4.6
Annual NO_X	2.0	1.3	0.7	2.0	1.3	0.7
Ozone Season NO_X	0.7	0.6	0.1	0.7	0.6	0.1

TABLE III.A–3—PROJECTED SO_2 AND NO_X EGU EMISSIONS IN COVERED STATES WITH THE TRANSPORT RULE COMPARED TO 2005 ACTUAL EMISSIONS

[Million tons]

	2005 Actual emissions	2012 Transport rule emissions	2012 Emissions reductions from 2005	2014 Transport rule emissions	2014 Emissions reductions from 2005
SO_2	8.9	3.4	5.5	2.6	6.3
Annual NO_X	2.7	1.3	1.4	1.3	1.4
Ozone Season NO_X	0.9	0.6	0.3	0.6	0.3

In addition to the emissions reductions shown previously, EPA projects other substantial benefits, as described in section IX in this preamble. Air quality modeling was used to quantify the improvements in $PM_{2.5}$ and ozone concentrations that are expected to result from the emissions reductions in 2014. The results of this modeling were used to calculate the average reduction in annual average $PM_{2.5}$, 24-hour average $PM_{2.5}$, and 8-hour ozone concentrations for monitoring sites in the eastern U.S. that are projected to be nonattainment in the 2014 base case. For annual $PM_{2.5}$ and 24-hour $PM_{2.5}$, the average reductions are 2.4 micrograms per cubic meter (μg/m^3) and 4.3 μg/m^3, respectively. The average reduction in 8-hour ozone at monitoring sites projected to be nonattainment in the 2014 base case is 0.3 parts per billion (ppb). The reductions in annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and ozone concentrations for individual nonattainment and/or maintenance sites are provided in section IX.

Table III.A–4 compares projected EGU emissions with the Transport Rule to projected EGU emissions with CAIR.

TABLE III.A–4—SIMPLE COMPARISON OF SO_2 AND NO_X EMISSIONS FROM ELECTRIC GENERATING UNITS IN STATES IN THE CAIR OR TRANSPORT RULE REGIONS * FOR EACH RULE

		2005	2012		2014	
		Actual	Transport rule	CAIR **	Transport rule	CAIR **
SO_2 (Million Tons)		9.5	4.1	5.1	3.3	4.6
NO_X (Million Tons)	Annual	2.9	1.6	1.7	1.6	1.7
	Ozone Season	1.0	0.7	0.8	0.7	0.8

* Emissions totals include states covered by either the Transport Rule or CAIR. For $PM_{2.5}$ (SO_2 and annual NO_X), the following 30 states are included: AL, CT, DE, DC, FL, GA, IL, IN, IA, KS, KY, LA, MD, MA, MI, MN, MS, MO, NE, NJ, NY, NC, OH, PA, SC, TN, TX, VA, WV, WI. For ozone (ozone-season NO_X), the following 30 states are included: AL, AR, CT, DE, DC, FL, GA, IL, IN, IA, KS, KY, LA, MD, MA, MI, MS, MO, NJ, NY, NC, OH, OK, PA, SC, TN, TX, VA, WV, WI.

** CAIR SO_2 totals are interpolations from emissions analysis originally done for 2010 and 2015. CAIR NO_X totals are as originally projected for 2010. This CAIR modeling represents a scenario that differed somewhat from the final CAIR (the modeling did not include a regionwide ozone season NO_X cap and included $PM_{2.5}$ requirements for the state of Arkansas).

[5] Projected Transport Rule emissions result from individual stae budgets in the proposed approach and include some banking of allowances in 2012 adn use of that bank in 2014.

[6] EPA's base case EGU emissions modeling does not assume enforceable SO_2 or NO_X reductions attributed to the Transport Rule or CAIR. In this base case, a unit with existing SO_2 or NO_X control equipment, but without an enforceable federal or state control requirement, is allowed to choose its most economic approach to operation within existing Acid Rain Program requirements and may opt not to operate a control. *See* section IV.C.1 and the IPM Documentation for further information on the base case modeling.

In addition to discussion of EPA's proposed regulatory approach (discussed in sections IV and V), this preamble also covers the stakeholder outreach EPA conducted (section VI), SIP submissions (section VII), permitting (section VIII), projected benefits of the proposed rule (section IX), economic impacts (section X), end-use energy efficiency (section XI), and statutory and executive order reviews (section XII).

Table III.A–5 shows the results of the cost and benefits analysis for the proposed and alternate remedies. Further discussion of these results is contained in preamble section XII-A and in the Regulatory Impacts Analysis. A listing of health and welfare effects is provided in RIA Table 1–6. Estimates here are subject to uncertainties discussed further in the body of the document. The social costs are the loss of household utility as measured in Hicksian equivalent variation. The capital costs spent for pollution controls installed for CAIR were not included in the annual social costs since the Transport Rule did not lead to their installation. Those CAIR-related capital investments are roughly estimated to have an annual social cost less than $1.15 to $ 1.29 billion (under the two discount rates.)

Most of the estimated PM-related benefits in this rule accrue to populations exposed to higher levels of $PM_{2.5}$. Of these estimated PM-related mortalities avoided, about 80 percent occur among populations initially exposed to annual mean $PM_{2.5}$ level of 10 μg/m³ and about 97 percent occur among those initially exposed to annual mean $PM_{2.5}$ level of 7.5 μg/m³. These are the lowest air quality levels considered in the Laden *et al.* (2006) and Pope *et al.* (2002) studies, respectively. This fact is important, because as we estimate PM-related mortality among populations exposed to levels of $PM_{2.5}$ that are successively lower, our confidence in the results diminishes. However, our analysis shows that the great majority of the impacts occur at higher exposures.

TABLE III.A–5—SUMMARY OF ANNUAL BENEFITS, COSTS, AND NET BENEFITS OF VERSIONS OF THE PROPOSED REMEDY OPTION IN 2014 [a]

[Billions of 2006$]

Description	Preferred remedy—State budgets/limited trading	Direct control	Intrastate trading
Social costs:			
3% discount rate	$2.03	$2.68	$2.49.
7% discount rate	$2.23	$2.91	$2.70.
Health-related benefits: [b, c]			
3% discount rate	$118 to $288 + B	$117 to $286 + B	$113 to $276 + B.
7% discount rate	$108 to $260 + B	$108 to $262 + B	$104 to $252 + B.
Net benefits (benefits-costs):			
3% discount rate	$116 to $286	$115 to $283	$110 to $273.
7% discount rate	$105 to $258	$105 to $259	$101 to $249.

Notes: (a) All estimates are rounded to three significant digits and represent annualized benefits and costs anticipated for the year 2014. For notational purposes, unquantified benefits are indicated with a "B" to represent the sum of additional monetary benefits and disbenefits. Data limitations prevented us from quantifying these endpoints, and as such, these benefits are inherently more uncertain than those benefits that we were able to quantify. (b) The reduction in premature mortalities account for over 90 percent of total monetized benefits. Benefit estimates are national. Valuation assumes discounting over the SAB-recommended 20-year segmented lag structure described in Chapter 5. Results reflect 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (U.S. EPA, 2000; OMB, 2003). The estimate of social benefits also includes CO_2-related benefits calculated using the social cost of carbon, discussed further in Chapter 5. Benefits are shown as a range from Pope *et al.* (2002) to Laden *et al.* (2006). Monetized benefits do not include unquantified benefits, such as other health effects, reduced sulfur deposition or visibility. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. (c) Not all possible benefits or disbenefits are quantified and monetized in this analysis. B is the sum of all unquantified benefits and disbenefits. Potential benefit categories that have not been quantified and monetized are listed in RIA Table 1–4.

B. Background

1. What is the source of EPA's authority for this action?

The statutory authority for this action is provided by the CAA, as amended (42 U.S.C. 7401 *et seq.*). Relevant portions of the CAA include, but are not necessarily limited to, sections 110(a)(2)(D), 110(c)(1), and 301(a)(1).

Section 110(a)(2)(D) of the CAA, often referred to as the "good neighbor" provision of the Act, requires states to prohibit certain emissions because of their impact on air quality in downwind states. Specifically, it requires all states, within 3 years of promulgation of a new or revised NAAQS, to submit SIPs that:

(D) Contain adequate provisions—

(i) Prohibiting, consistent with the provisions of this subchapter, 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, or

(II) Interfere with measures required to be included in the applicable implementation plan for any other State under part C of this subchapter to prevent significant deterioration of air quality or to protect visibility.

(ii) Insuring compliance with the applicable requirements of sections 7426 and 7415 of this title (relating to interstate and international pollution abatement). 42 U.S.C. 7410(a)(2)(D).

This proposal addresses the requirement in section 110(a)(2)(D)(i)(I) regarding the prohibition of emissions within a state that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any other state. As discussed in greater detail later, EPA has previously issued two rules interpreting and clarifying the requirements of section 110(a)(2)(D)(i)(I). The NO_X SIP Call, promulgated in 1998, was largely upheld by the U.S. Court of Appeals for the DC Circuit in *Michigan* v. *EPA*, 213 F.3d 663 (DC Cir. 2000). The CAIR, promulgated in 2005, was remanded by the DC Circuit in *North Carolina* v. *EPA*, 531 F.3d 896 (DC Cir. 2008), *modified on reh'g*, 550 F.3d. 1176 (DC Cir. 2008). These decisions provide additional guidance regarding the requirements of section 110(a)(2)(D)(i)(I) and are discussed later in this section.

Section 301(a)(1) of the CAA gives the Administrator of EPA general authority to "prescribe such regulations as are necessary to carry out [her] functions under this chapter." 42 U.S.C. 7601(a)(1). Pursuant to this section, EPA has authority to clarify the applicability of CAA requirements. In this action, EPA is clarifying the applicability of section 110(a)(2)(D)(i)(I) by proposing to identify SO_2 and NO_X emissions that each affected state must prohibit pursuant to that section with respect to the $PM_{2.5}$ NAAQS promulgated in 1997 and 2006 and the 8-hour ozone NAAQS promulgated in 1997. The improvements in air quality that would result from the reductions in upwind state emissions that EPA is proposing to require would assist downwind states affected by transported pollution in developing, pursuant to section 110 of the CAA, their SIPs to provide for expeditious attainment and maintenance of the NAAQS.

Section 110(a) of the CAA assigns to each state both the primary responsibility for attaining and maintaining the NAAQS within such state, 42 U.S.C. 7410(a)(1), and the primary responsibility for prohibiting emissions activity within the state which will significantly contribute to nonattainment or interfere with maintenance in a downwind area. 42 U.S.C. 7410(a)(2)(D)(i)(I). States fulfill these CAA obligations through the SIP process described in section 110(a) of the Act.

Section 110(c)(1) of the Act, however, requires EPA to act when a state has not been able to or has not fulfilled its obligation to submit a SIP that meets the requirements of the Act. Specifically, section 110(c)(1) provides that: The Administrator shall promulgate a Federal implementation plan at any time within 2 years after the Administrator—

(A) Finds that a State has failed to make a required submission or finds that the plan or plan revision submitted by the State does not satisfy the minimum criteria established under subsection (k)(1)(A) of this section, or

(B) Disapproves a State implementation plan submission in whole or part, unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan.

42 U.S.C. 7410(c)(1). Section 110(k)(1)(A), in turn, calls for the Administrator to establish criteria for determining whether SIP submissions are complete. 42 U.S.C. 7410(k)(1)(A).

As discussed in greater detail in section VII, for all states covered by the FIPs proposed in this action, EPA either has taken, has proposed to take, or believes it may need to take one of the following actions with respect to the 1997 ozone NAAQS, the 1997 $PM_{2.5}$ NAAQS and/or the 2006 $PM_{2.5}$ NAAQS: (1) Find that the state has failed to make a SIP submission required by section 110(a)(2)(D)(i)(I) or section 110(k)(5) of the Act; (2) find that such a SIP submission is incomplete; or (3) disapprove such a SIP submission. Once EPA has taken one of the these actions, pursuant to section 110(c)(1), it has authority to promulgate a FIP directly implementing the requirements of section 110(a)(2)(D)(i)(I), provided the state has not submitted and EPA has not approved a SIP submission that corrects the SIP deficiency prior to promulgation of the FIP.

2. What air quality problems does this proposal address?

a. Fine Particles

Fine particles are associated with a number of serious health effects including premature mortality, aggravation of respiratory and cardiovascular disease (as indicated by increased hospital admissions, emergency room visits, health-related absences from school or work, and restricted activity days), lung disease, decreased lung function, asthma attacks, and certain cardiovascular problems. *See* EPA, Air Quality Criteria for Particulate Matter (EPA/600/P–99/002bF, October 2004) at 9.2.2.3. *See* also integrated science assessment for the PM NAAQS review, December 2009, *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546.* Individuals particularly sensitive to fine particle exposure include older adults, people with heart and lung disease, and children. This rule, and the NAAQS to which it is related, consider the effects of fine particles on vulnerable populations (*see* further discussion in section XII.G and section XII.J of this notice). More detailed information on health effects of fine particles can be found on EPA's Web site at: *http://epa.gov/pm/standards.html.*

In addition to effects on public health, fine particles are linked to a number of public welfare effects. First, $PM_{2.5}$ are the major cause of reduced visibility (haze) in parts of the United States, including many of our national parks and wilderness areas. For more information about visibility, visit EPA's Web site at *http://www.epagov/visibility.* Second, particles can be carried over long distances by wind and then settle on ground or water. The effects of this settling include: Making lakes and streams acidic; changing the nutrient balance in coastal waters and large river basins; depleting the nutrients in soil; damaging sensitive forests and farm crops; and affecting the diversity of ecosystems. More information about these effects is available at EPA's Web site at *http://www.epa.gov/acidrain/effects/index.html.* Finally, particle pollution can stain and damage stone and other materials, including culturally important objects such as statues and monuments.

In 1997, EPA revised the NAAQS for PM to add new annual average and 24-hour standards for fine particles, using $PM_{2.5}$ as the indicator (62 FR 38652). These revisions established an annual standard of 15 $\mu g/m^3$ and a 24-hour standard of 65 $\mu g/m^3$. During 2006, EPA revised the air quality standards for $PM_{2.5}$. The 2006 standards decreased the level of the 24-hour fine particle standard from 65 $\mu g/m^3$ to 35 $\mu g/m^3$, and retained the annual fine particle standard at 15 $\mu g/m^3$.

In the preamble to the final rule for CAIR in May 2005, EPA discussed ambient monitoring for 2001–2003, the most recent 3-year period available at the time. These results showed widespread exceedances of the 15 $\mu g/m^3$ annual $PM_{2.5}$ standard in the eastern United States, with additional exceedances in parts of California and one county in Montana. At that time, 82 counties in the U.S. had at least one monitor that violated the 1997 annual $PM_{2.5}$ standard.

The $PM_{2.5}$ ambient air quality monitoring for the 2006–2008 period (most recent available) shows significant improvements. Nonetheless, areas which continue to violate the 15 $\mu g/m^3$ annual $PM_{2.5}$ standard are located across a significant portion of the eastern half of the United States, in parts of California and one county in Arizona. Based on these nationwide data, 23 counties have at least one monitor that violates the annual $PM_{2.5}$ standard.

The $PM_{2.5}$ ambient air quality monitoring for this same 2006–2008 time period shows that areas violating the 2006 24-hour $PM_{2.5}$ standard of 35 $\mu g/m^3$ (*i.e.*, the revised 2006 standard for 24-hour $PM_{2.5}$) are located across much of the eastern half of the United States, in parts of California, and in some counties in several other western states—Alaska, Washington, Oregon, Utah, and Arizona. Based on these nationwide data, 52 counties have at least one monitor that violates the 24-hour $PM_{2.5}$ standard.

EPA believes that a great deal of the improvement in $PM_{2.5}$ annual and 24-hour concentrations in the eastern U.S. can be attributed to EGU SO_2 reductions achieved due to the CAIR. While the CAIR requirements related to SO_2 did not begin until 2010, many actions were taken by EGU owners and operators in anticipation of those requirements. Emissions of SO_2 from EGUs covered by the CAIR that were also in the acid rain program (under CAA Title IV) tracking system decreased from 10.2 million tons in 2005 to 7.6 million tons in 2008. Almost all of these emissions reductions were achieved in the areas of the eastern United States covered by the CAIR. See *http://www.epa.gov/airmarkt/progress/ARP_4.html*. EPA believes that there would be substantially more nonattainment counties for both the annual and 24-hour standards if the CAIR were not in effect.

As required by the CAA, and in response to litigation over the 2006 standards, EPA is currently conducting a review of the 2006 $PM_{2.5}$ standards. Information and documents related to this review are available at: *http://epa.gov/ttn/naaqs/standards/pm/s_pm_index.html*. EPA expects to complete this review and to publish any revised standards that may result from the review by October 2011. EPA is planning to propose the revised standards by February 2011.

b. Ozone

Short-term (1- to 3-hour) and prolonged (6- to 8-hour) exposures to ambient ozone have been linked to a number of adverse health effects. At sufficient concentrations, short-term exposure to ozone can irritate the respiratory system, causing coughing, throat irritation, and chest pain. Ozone can reduce lung function and make it more difficult to breathe deeply. Breathing may become more rapid and shallow than normal, thereby limiting a person's normal activity. Ozone also can aggravate asthma, leading to more asthma attacks that may require a doctor's attention and the use of additional medication. Increased hospital admissions and emergency room visits for respiratory problems have been associated with ambient ozone exposures. Longer-term ozone exposure can inflame and damage the lining of the lungs, which may lead to permanent changes in lung tissue and irreversible reductions in lung function. A lower quality of life may result if the inflammation occurs repeatedly over a long time period (such as months, years, or a lifetime). There is also recent epidemiological evidence indicating that there is a correlation between short-term ozone exposure and premature mortality.

People who are particularly susceptible to the effects of ozone include people with respiratory diseases, such as asthma. Those who are exposed to higher levels of ozone include adults and children who are active outdoors. This rule, and the NAAQS which it is related to, consider the effects of ozone on vulnerable populations (*see* further discussion in section XII.G and section XII.J of this notice).

In addition to causing adverse health effects, ozone affects vegetation and ecosystems, leading to reductions in agricultural crop and commercial forest yields; reduced growth and survivability of tree seedlings; and increased plant susceptibility to disease, pests, and other environmental stresses (*e.g.*, harsh weather). In long-lived species, these effects may become evident only after several years or even decades and have the potential for long-term adverse impacts on forest ecosystems. Ozone damage to the foliage of trees and other plants can also decrease the aesthetic value of ornamental species used in residential landscaping, as well as the natural beauty of our national parks and recreation areas. More detailed information on effects of ozone can be found at the following EPA Web site: *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_index.html*.

In 1997, at the same time we revised the $PM_{2.5}$ standards, EPA issued its final action to revise the NAAQS for ozone (62 FR 38856) to establish new 8-hour standards. In this action published on July 18, 1997, we promulgated identical revised primary and secondary ozone standards that specified an 8-hour ozone standard of 0.08 parts per million (ppm). Specifically, the standards require that the 3-year average of the fourth highest 24-hour maximum 8-hour average ozone concentration may not exceed 0.08 ppm. In general, the 8-hour standards are more protective of public health and the environment and more stringent than the pre-existing 1-hour ozone standards.

At the time EPA published the CAIR and the CAIR FIP rulemakings, wide geographic areas, including most of the nation's major population centers, experienced ozone levels that violated the 1997 NAAQS of 8-hour ozone 0.08 ppm (effectively 0.084 ppm as a result of rounding). These areas included much of the eastern part of the United States and large areas of California. The EPA published the 8-hour ozone attainment and nonattainment designations in the **Federal Register** on April 30, 2004 (69 FR 23858). These designations, based on ozone season monitoring data for the 2001–2003 time period, resulted in 112 areas designated as nonattainment. As of December 2009, significant emissions reductions have allowed 58 of the original 112 nonattainment areas to be re-designated to attainment. In addition, a number of areas still designated as nonattainment ozone monitoring data for 2006–2008 (most recent data available) show levels below the standard. EPA believes a number of factors contributed to NO_X emissions reductions subsequent to the 2001–2003 time period. First, EGU emissions were substantially reduced as EGUs in the eastern U.S. came into compliance with the NO_X SIP Call. A series of progress reports discussing the effect of the NO_X SIP Call reductions can be found on EPA's Web site at: *http://www.epa.gov/airmarkets/progress/progress-reports.html*. Additional information on emissions and air quality trends are available in EPA's 2007 and 2008 air quality trends reports, which are available at: *http://www.epa.gov/airtrends/*.

Second, mobile source emissions standards for onroad gasoline and vehicle emissions standards began to reduce mobile source emissions as the fleet began turning over vehicles to meet tightened NO_X emissions standards. Continued improvement in ozone is expected with continued reductions in mobile source emissions.

On March 12, 2008, EPA published a revision to the 8-hour ozone standard, lowering the level from 0.08 ppm to 0.075 ppm. On September 16, 2009, EPA announced it would reconsider these 2008 ozone standards. The purpose of the reconsideration is to ensure that the ozone standards are clearly grounded in science, protect public health with an adequate margin of safety, and are sufficient to protect the environment. EPA proposed revisions to the standards on January 19, 2010 (75 FR 2938) and will issue final standards soon. Information on the 2008 revisions to the ozone standard, and on all subsequent activity based on the reconsideration, is available at: *http://www.epa.gov/air/ozonepollution/actions.html#sep09s*.

3. Which NAAQS does this proposal address?

This proposed action addresses the requirements of CAA section 110(a)(2)(D)(i)(I) as they relate to:

(1) The 1997 annual $PM_{2.5}$ standards,

(2) The 2006 daily $PM_{2.5}$ standards, and

(3) The 1997 ozone standards

The original CAIR and CAIR FIP rules, which pre-dated the 2006 standards, addressed the 1997 ozone and $PM_{2.5}$ standards only. The 1997 8-hour ozone standard is 0.08 ppm. The 1997 $PM_{2.5}$ standards promulgated in 1997 established a 15 μg/³ standard for 24-hour $PM_{2.5}$ and a 65 μg/m³ standard for annual $PM_{2.5}$. In 2006, the 24-hour $PM_{2.5}$ standard was lowered to 35 μg/m³ and the 15 μg/m³ annual $PM_{2.5}$ standard was left unchanged.

For this proposal, EPA fully addresses the requirements of CAA section 110(a)(2)(D)(i)(I) for the annual $PM_{2.5}$ standard of 15 μg/m^3. For the 24-hour standard of 35 μg/m^3 and for the 1997 8-hour ozone standard of 0.08 ppm, EPA fully addresses the CAA section 110(a)(2)(D)(i)(I) requirements for some states, but for the remaining states EPA will address whether further requirements are needed.

This action does not address the CAA section 110(a)(2)(D)(i)(I) requirements for the revised ozone standards promulgated in 2008. These standards are currently under reconsideration. We are, however, actively conducting the technical analyses and other work needed to address interstate transport for the reconsidered ozone standard as soon as possible. We intend to issue as soon as possible a proposal to address the transport requirements with respect to the reconsidered standard.

4. EPA Transport Rulemaking History

a. CAA Provisions

For almost 40 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)(i)(I), which is key to the present action, is described in more detail later.

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).

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 expeditious as practicable, but not to exceed 10 years from the date of designation (section 172(a)).

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)). If states do not submit SIPs in a timely or approvable manner, EPA has the authority to make findings of failure to submit or impose FIPs on specific sources in the state that contribute to downwind nonattainment and interference with maintenance. Significant contribution and interference with maintenance are discussed in detail in section IV later.

The 1990 Amendments reflect general awareness by Congress that ozone is a regional, and not merely a local, problem. Ozone and its precursors may be transported long distances across state lines, thereby exacerbating ozone problems downwind. Ozone transport is recognized as a major reason for the persistence of the ozone problem, notwithstanding the imposition of numerous controls, both Federal and State, across the country.

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.[7]

In addition, the 1990 Amendments added section 184, which delineates a multi-state 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 authorized the formation of transport regions for other pollutants and in other parts of the country.

In September 1994, the Northeast OTC states signed a Memorandum of Understanding (MOU) committing to reduce NO_X emissions throughout the region. In 1999 through 2002, most of the OTC states achieved substantial NO_X reductions through an ozone season cap and trade program for NO_X called the OTC NO_X Budget Program, which EPA administered, and through NO_X emissions rate limits from certain coal plants under Title IV.

Separate from activity in the OTC, EPA and the Environmental Council of the States (ECOS) formed the OTAG in 1995. This workgroup brought together interested states and other stakeholders, including industry and environmental groups. Its primary objective was to assess the ozone transport problem and develop a strategy for reducing ozone pollution throughout the eastern half of the United States.

Notwithstanding significant efforts, the states generally were not able to meet the November 15, 1994 statutory deadline for the attainment demonstration and rate of progress (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, 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, EPA established new timeframes for the required SIP submittals. To allow time for states to incorporate the results of the OTAG

[7] In addition, section 115 authorizes EPA to require a SIP revision in certain circumstances 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."

modeling into their local plans, EPA extended the submittal date to April 1998.[8] The OTAG's air quality modeling and recommendations formed the basis for what became the NO_X SIP Call rulemaking and included the most comprehensive analyses of ozone transport ever conducted. The EPA participated extensively in the OTAG process that generated much useful technical and modeling information on regional ozone transport.

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. They found that ozone transport caused problems for downwind areas under either the 1-hour or 8-hour standard.

EPA's Transport SIP Call Regulatory Efforts. Shortly after OTAG began its work, EPA indicated 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 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. In light of OTAG's work and additional information, EPA was 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 the rulemaking. The regional reductions of NO_X that would have been achieved through this SIP call for the 1-hour NAAQS were key components for meeting the new 8-hour ozone standard in a cost-effective manner. Therefore, EPA believed that the OTAG recommendations for how to address ozone transport were valid for both NAAQS.

The EPA published a supplemental notice of proposed rulemaking (SNPR) 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.

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 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 provided increased protection to the public, especially children and other at-risk populations, against a wide range of ozone-induced health effects.

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 provided increased protection to the public welfare against ozone-induced effects on vegetation.

Section 126 Petitions. In a separate rulemaking, EPA proposed action on petitions submitted by 8 northeastern states[9] under section 126 of the CAA. Each petition specifically requested that EPA make a finding that NO_X emissions from certain major stationary sources significantly contributed to ozone nonattainment problems in the petitioning state. Both the NO_X SIP Call and the section 126 petitions were designed to address ozone transport through reductions in upwind NO_X emissions. However, the EPA's response to the section 126 petitions differed from EPA's action in the NO_X SIP Call rulemaking in several ways. In the NO_X SIP Call, EPA was determining that certain states were or would be significantly contributing to nonattainment or maintenance problems in downwind states. The EPA required the upwind states to submit SIP provisions to reduce the amounts of each state's NO_X emissions that significantly contributed to downwind air quality problems. The states had the discretion to select the mix of control measures to achieve the necessary reductions. By contrast, under section 126, if findings of significant contribution were made for any sources identified in the petitions, EPA would have determined the necessary emissions limits to address the amount of significant contribution and would have directly regulated the sources. A section 126 remedy would have applied only to sources in states named in the petitions.

b. NO_X SIP Call

Based on the findings of OTAG, EPA proposed a rulemaking known as the NO_X SIP Call in 1997 and finalized it in 1998. (*See* "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule," (63 FR 57356).) This rule concluded that NO_X emissions in 22 states and the District of Columbia contribute to ozone nonattainment in other states, and the rule required affected states to amend their SIPs and limit NO_X emissions. EPA set an ozone season NO_X budget for each affected state, essentially a cap on ozone season (summertime) NO_X emissions in the state. Sources in the affected states were given the option to participate in a regional cap and trade program. The first control period was scheduled for the 2003 ozone season.

In response to litigation over EPA's final NO_X SIP Call rule, the Court issued two decisions concerning the NO_X SIP Call and its technical amendments.[10] The Court decisions, discussed later, generally upheld the NO_X SIP Call and technical amendments, including EPA's interpretation of the definition of "contribute significantly" under CAA section 110(a)(2)(D). The litigation over the NO_X SIP Call coincided with the litigation over the 8-hour NAAQS. Because of the uncertainty caused by the litigation on the 8-hour NAAQS, EPA stayed the portion of the NO_X SIP Call based on the 8-hour NAAQS (65 FR 56245, September 18, 2000). Therefore, for the most part, the Court did not address NO_X SIP Call requirements under the 8-hour ozone NAAQS.

(1) What was the NO_X SIP Call?

The NO_X SIP Call was EPA's principal effort to reduce interstate transport of precursors for both the 1-hour ozone NAAQS and the 8-hour ozone NAAQS. The EPA's rulemaking was 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 believed

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

[9] The 8 states were Connecticut, Massachusetts, Maine, New Hampshire, New York, Pennsylvania, Rhode Island, and Vermont.

[10] *See Michigan* v. *EPA,* 213 F.3d 663 (DC Cir. 2000), cert. denied, 532 U.S. 904 (2001) (NO_X SIP call) and *Appalachian Power* v. *EPA,* 251 F.3d 1026 (DC Cir. 2001) (technical amendments).

that requiring NO_X emissions reductions across the region in amounts achievable by uniform controls was a reasonable, cost-effective step to take to mitigate ozone nonattainment in downwind states for both the 1-hour and 8-hour standards.

It was also EPA's goal to ensure that sufficient regional reductions were 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.

This NO_X SIP Call required those jurisdictions that EPA determined significantly contribute to 1-hour and 8-hour ozone nonattainment problems in downwind states to revise their SIPs to include NO_X control measures to mitigate the significant ozone transport during summer months known as the "ozone season" (May–September). The EPA determined emissions reductions requirements for the covered states and source categories (*see* section IV.A for a description of the approach EPA used to determine emissions reductions requirements). The affected states were required to submit SIPs providing the specified amounts of emissions reductions. By eliminating these amounts of NO_X emissions, the control measures would assure that the remaining NO_X emissions would meet the level identified in the rule as the state's NO_X emissions budget and would not "significantly contribute to nonattainment, or interfere with maintenance by," a downwind state, under section 110(a)(2)(D)(i)(I).

The SIP requirements permitted 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 decreased NO_X emissions primarily from large stationary sources in a trading program, EPA encouraged states to consider electric utility and large boiler controls under a cap and trade program as a cost-effective strategy. The EPA also recognized that promotion of energy efficiency could contribute to a cost-effective strategy. *See* section V.D.1 for a discussion on the approach taken to implement the emissions reductions requirements in the NO_X SIP Call.

(2) Legal Challenges to the NO_X SIP Call

Several petitioners challenged the NO_X SIP Call in the United States Court of Appeals for the District of Columbia Circuit (DC Circuit). In *Michigan* v. *EPA*, 213 F.3d 663 (DC Cir., 2000), *cert. denied*, 532 U.S. 904 (2001), the Court upheld the rule in most respects. Of greatest relevance here, the Court upheld the essential features of EPA's approach to identifying and eliminating states" NO_X emissions that significantly contribute to downwind nonattainment. It upheld key aspects of EPA's air quality modeling and its use of cost-effectiveness criteria in defining states" "significant contribution." *See id.* at 673–79. In addition, it accepted EPA's use of a uniform control requirement (*i.e.*, requiring all covered jurisdictions, regardless of amount of contribution, to reduce NO_X emissions by an amount achievable with highly cost effective controls). *See id.* at 679–80. The Court, however, agreed with petitioners that certain specific applications of EPA's approach were flawed. It thus vacated the rule with respect to Wisconsin, Missouri, and Georgia, and held that EPA had failed to provide adequate notice on two specific issues (a change in the definition of EGU and a change in control level assumed for specific sources). *See id.* at 681–85, 692–94. The Court also subsequently delayed the implementation date to May 31, 2004. *Michigan* v. *EPA, 2000 WL 1341477 (DC Cir. 2000).*

The decision resolved only issues involving the 1-hour ozone NAAQS and did not resolve any issues involving the 8-hour NAAQS, which provided another basis for the rule. *See id.* at 670–71. EPA ultimately stayed the 8-hour basis of the NO_X SIP Call. *See* 65 FR 56245. In addition, in a subsequent case that reviewed separate EPA rulemakings making technical corrections to the NO_X SIP Call, the DC Circuit remanded the case for a better explanation of EPA's methodology for computing the growth component in the EGU heat input calculation. *See Appalachian Power Co.* v. *EPA*, 251 F.3d 1026 (DC Cir. 2001). More recently, the Court also rejected a challenge to a subsequent EPA rule withdrawing EPA's findings of significant contribution for Georgia for the 1-hour ozone standard. *See North Carolina* v. *EPA*, 587 F.3d 422 (DC Cir. 2009).

(3) How the NO_X Budget Trading Program (NBP) Worked

The NBP was a market-based cap and trade program created to reduce the regional transport of emissions of NO_X from power plants and other large combustion sources that contribute to ozone nonattainment in the eastern United States. Over six ozone seasons (2003–2008), the NBP significantly lowered NO_X emissions from affected sources, contributing to improvements in regional air quality across the Midwest, Northeast, and Mid-Atlantic. The cap level was intended to protect public health and the environment and to sustain that protection into the future regardless of growth in the affected sector. Ozone season NO_X emissions decreased from levels in baseline years in all states participating in the NBP. (All NBP states transitioned to the CAIR NO_X ozone season program in 2009 except Rhode Island.) Allowance trading was generally active from the start of the program in 2003. Prices and trading were down in 2008, primarily due to uncertainty. Compliance remained virtually 100 percent throughout the program's 6 years. Many nonattainment areas in the East saw substantial improvements in air quality concentrations that brought them in line with ozone NAAQS. The NBP, together with other Federal, State, and local programs, contributed to NO_X reductions that have led to improvements in ozone and $PM_{2.5}$, saving 580–1,800 lives annually in 2008.[11] Changes in ozone and nitrate concentrations due to the NBP have also contributed to improvements in ecosystems in the East.

EPA stopped administering the NBP at the conclusion of 2008 control period activities. States still have the emissions reductions requirement and could use the CAIR NO_X ozone season trading program to achieve this.

See section V.D.4.e. for a discussion of the results of the NO_X Budget Trading Program.

(4) Clean Air Interstate Rule

Following promulgation of the new NAAQS in 1997, the CAA required all states, regardless of whether they have attainment air quality in all areas, to submit SIPs containing provisions specified under section 110(a)(2). In addition, states are required to submit SIPs for nonattainment areas which are generally required to include additional emissions controls providing for attainment of the NAAQS.

As described previously, section 110(a)(2)(D)(i)(I) provides a tool for addressing the problem of transported pollution that significantly contributes to downwind nonattainment and maintenance problems. Under section 110(a)(2)(D), a SIP must contain adequate provisions prohibiting sources in the state from emitting air pollutants in amounts that would 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 is to require the state

[11] U.S.EPA. September, 2009. *The NO_X Budget Trading Program: 2008 Environmental Results*, p.9.

to submit, within a specified period, a SIP revision to correct the inadequacy ("SIP call"). In 1998, EPA used this authority to issue the NO_X SIP Call, discussed previously, to require states to revise their SIPs to include measures to reduce NO_X emissions that were significantly contributing to ozone nonattainment problems in downwind states.

Sulfur dioxide and NO_X are not the only emissions that contribute to interstate transport and $PM_{2.5}$ nonattainment. However, EPA stated in the CAIR that it believed that, given current knowledge, it was not appropriate to specify emissions reductions requirements for direct $PM_{2.5}$ emissions or organic precursors (*e.g.*, volatile organic compounds (VOCs) or ammonia (NH_3)). Similarly, for 8-hour ozone, EPA continued to rely on the conclusion of the OTAG that analysis of interstate transport control opportunities should have focused on NO_X, rather than VOCs. [12]

(5) What is the CAIR?

The CAA contains a number of requirements to address nonattainment of the $PM_{2.5}$ and the 8-hour ozone NAAQS, including requirements that states address interstate transport that significantly contributes to such nonattainment. [13] Based on air quality modeling, ambient air quality data analyses, and cost analyses, EPA found that emissions in certain upwind states resulted in amounts of transported $PM_{2.5}$, ozone, and their emissions precursors that significantly contributed to nonattainment in downwind states.

In the CAIR, promulgated on May 12, 2005 (70 FR 25162), EPA required SIP revisions in 28 states and the District of Columbia, within 18 months after publication of the notice of final rulemaking, to ensure that certain emissions of SO_2 and/or NO_X—important precursors of $PM_{2.5}$ (NO_X and SO_2) and ozone (NO_X)—were prohibited. Achieving the emissions reductions identified, EPA concluded, would address the states' requirements under section 110(a)(2)(D)(i)(I) of the CAA and would help $PM_{2.5}$ and ozone nonattainment areas in the eastern half of the United States attain the standards. Moreover, EPA concluded that such attainment would be achieved in a more certain, equitable, and cost-effective manner than if each nonattainment area attempted to implement local emissions reductions alone, and would also assist the covered states and their neighbors in making progress toward their visibility goals.

The CAIR built on EPA's efforts in the NO_X SIP Call to address interstate pollution transport for ozone, and was EPA's first attempt to address interstate pollution transport for $PM_{2.5}$. It required significant reductions in emissions of SO_2 and NO_X, which contribute to fine particle concentrations. In addition, NO_X emissions contribute to ozone problems. EGUs were found to be a major source of the SO_2 and NO_X emissions which contributed to fine particle concentrations and ozone problems downwind.

CAIR was designed to provide significant air quality attainment, health, and environmental improvements across the eastern U.S. in a highly cost-effective manner by reducing SO_2 and NO_X emissions from EGUs that contribute to the $PM_{2.5}$ and 8-hour ozone problems described in the rule. CAIR's emissions reductions requirements were based on controls that EPA had determined to be highly cost-effective for EGUs under optional cap and trade programs. However, states had the flexibility to choose the measures to adopt to achieve the specified emissions reductions. EPA required the emissions reductions to be implemented in two phases, with the first phase in 2009 and 2010 (for NO_X and SO_2, respectively), and the second phase for both pollutants in 2015. These requirements are described in more detail in section V.D.1.

In addition to promulgating findings of significant contribution to nonattainment, EPA assigned emissions reductions requirements for SO_2 and/or NO_X that each of the identified states must meet through SIP measures.

Section V.D.1 discusses the approach taken in CAIR using three model multi-state cap and trade programs for SO_2 and NO_X that EPA developed and that states could choose to adopt to meet the required emissions reductions in a flexible and cost-effective way.

The requirements in the CAIR were intended to address regional interstate transport of air pollution. EPA recognized, however, that additional local reductions might be necessary to bring some areas into attainment even after significantly contributing upwind emissions were eliminated. 70 FR 25165–66, May 12, 2005. In addition, states that shared an interstate nonattainment area were expected to work together in developing the nonattainment SIP for that area, reducing emissions that contributed to local-scale interstate transport problems.

CAIR FIPs. When EPA promulgated the final CAIR in May 2005, EPA also issued a national finding that states had failed to submit SIPs to address the requirements of CAA section 110(a)(2)(D)(i) with respect to the 1997 ozone and $PM_{2.5}$ NAAQS. States were to have submitted 110(a)(2)(D)(i) SIPs for those standards by July 2000. This action triggered a 2-year clock for EPA to issue FIPs to address interstate transport. On March 15, 2006 the EPA promulgated FIPs to ensure that the emissions reductions required by the CAIR are achieved on schedule. The FIPs did not limit states" flexibility in meeting their CAIR requirements as all states remained free to submit SIPs at any time that, if approved by EPA, would replace the FIP for that state.

As the control strategy for the FIPs, EPA adopted the model cap and trade programs that it provided in the CAIR as a control option for states, with minor changes to account for federal, rather than state, implementation. The FIPs required power plants in affected states to participate in one or more of three separate emissions cap and trade programs that cover: (1) Annual SO_2 emissions, (2) annual NO_X emissions, and (3) ozone season NO_X emissions. Emission cap and trade programs are a proven method for achieving highly cost-effective emissions reductions while providing regulated sources with flexibility in choosing compliance strategies.

The FIPs also provided states with an option to submit abbreviated SIPs to meet CAIR. Under this option, states could save the time and resources needed to develop the complete trading program SIP, while still being able to make key decisions, such as the methodology for allocating annual and/or ozone season NO_X allowances.

New Jersey and Delaware. Separately, on March 15, 2006, EPA issued a final rule to include Delaware and New Jersey in the CAIR to control SO_2 and NO_X emissions because they contribute to $PM_{2.5}$ nonattainment in other states. 71 FR 25288, April 28, 2006. These states were already included in the CAIR because their sources contributed to nonattainment of other states' 8-hour ozone air quality standard. The CAIR FIP established requirements for Delaware and New Jersey with respect to both ambient air quality standards.

(6) Legal Challenges to the CAIR

Petitions for review challenging various aspects of the CAIR were filed in the U.S. Court of Appeals for the DC Circuit. In *North Carolina* v. *EPA,* 531

[12] The OTAG was active from 1995–1997 and consisted of representatives from the 37 states in that region; the District of Columbia; EPA; and interested members of the public, including industry and environmental groups. *See* discussion below under NO_X SIP Call for further information on OTAG.

[13] The term "transport" includes the transport of both $PM_{2.5}$ and their precursor emissions and/or transport of both ozone and its precursor emissions.

F.3d 896, *modified on reh'g* 550 F.3d 1176 (D.C. Cir. 2008), the Court granted several of the petitions for review and remanded the rule to EPA for further proceedings. In its July 2008 opinion, *North Carolina,* 531 F.3d 896, the Court upheld several challenged aspects of EPA's approach, but also found fatal flaws in the rule—flaws it found significant enough to warrant vacatur of the CAIR and the associated FIPs in their entirety. In December 2008, however, the Court responded to petitions for rehearing and determined that "notwithstanding the relative flaws of CAIR, allowing the CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values covered by CAIR." *North Carolina,* 550 F.3d at 1178. Accordingly, it decided to remand the rule without vacatur "so that EPA may remedy CAIR's flaws in accordance with [the Court's] July 11, 2008 opinion in this case." *Id.*

Although the entire rule was remanded, important parts of EPA's rulemaking were upheld by the Court in its July 2008 ruling. The Court upheld key aspects of the air quality modeling portion of EPA's significant contribution analysis. It upheld EPA's decision to consider upwind states for inclusion in the CAIR only if those states contributed to projected nonattainment in 2010. *See North Carolina,* 531 F.3d at 913–914. The Court further upheld the contribution threshold used in the air quality modeling portion of the significant contribution analysis for $PM_{2.5}$, EPA's use of whole states as the unit of measurement, and the first-phase NO_X compliance deadline of 2009 *See id.* at 914–17, 923–27, 928–29.

The Court also found significant flaws in EPA's approach. The Court emphasized the importance of individual state contributions to downwind nonattainment areas and held that EPA had failed to adequately measure significant contribution from sources within an individual state to downwind nonattainment areas in other states. *Id.* at 907. Further, the Court noted that EPA had not provided adequate assurance that the trading programs established in the CAIR would achieve, or even make measurable progress towards achieving, the section 110(a)(2)(D)(i)(I) mandate to eliminate significant contribution. *See North Carolina,* 532 F.3d at 907–08. For these reasons, it concluded that EPA had not shown that the CAIR rule would achieve measurable progress towards satisfying the statutory mandate of section 110(a)(2)(D)(i)(I) and thus EPA lacked authority for its action. *See id.* at 908. Moreover, it emphasized that where the rule constitutes a complete 110(a)(2)(D)(i)(I) remedy, it must actually require the elimination of emissions that contribute significantly to nonattainment or interfere with maintenance downwind. *See id.*

The Court further rejected the state budgets for SO_2 and NO_X which were used to implement the CAIR trading programs, finding the budgets to be insufficiently related to the 110(a)(2)(D)(i)(I) mandate of eliminating significant contribution and interference with maintenance. *See id.* at 916–21. It also rejected EPA's effort to harmonize the CAIR SO_2 trading program with the existing requirements of Title IV of the CAA, holding that section 110(a)(2)(D)(i)(I) did not give EPA authority to terminate or limit Title IV allowances. In addition, the Court found that EPA had failed to give meaning to the "interfere with maintenance" prong of section 110(a)(2)(D)(i)(I), that EPA had not demonstrated that the 2015 compliance deadline used in the CAIR was coordinated with the downwind state's deadlines for attaining the NAAQS, and that EPA had not adequately supported its determination that sources in Minnesota significantly contributed to nonattainment or interfered with maintenance in downwind states. *See id.* at 908–11, 911–13, and 926–28.

(7) How the Clean Air Interstate Rule Worked

Building on the emissions reductions under the NBP and Acid Rain Program (ARP), CAIR was designed to permanently lower emissions of SO_2 and NO_X in the eastern United States. As explained previously, although the DC Circuit remanded the rule to EPA, it did so without vacatur allowing the rule to remain in effect while EPA addresses the remand. Thus, CAIR is continuing to help states address ozone and $PM_{2.5}$ nonattainment and improve visibility, reducing transported precursors of SO_2 and NO_X, through the implementation of three separate cap and trade compliance programs for annual NO_X, ozone season NO_X, and annual SO_2 emissions from power plants.

See section V.D.4.e. for a discussion on CAIR implementation in 2009, the first year of the NO_X annual and ozone season programs. The CAIR annual SO_2 program began January 1, 2010. Quarterly emissions will be posted on EPA's web site (*see http://camddataandmaps.epa.gov/gdm/*) and an assessment of emissions reduction data will be available at the end of each compliance period.

C. What are the goals of this proposed rule?

In developing this proposed rule, EPA was guided by a number of goals and guiding principles, as discussed in this section of the preamble.

1. Primary Goals

a. Respond to the Court Remand of the CAIR

Most importantly, this proposal responds to the remand of the CAIR by the Court. As noted previously, the Court granted several petitions for review of the CAIR, finding fatal flaws with the rule; yet, it ultimately decided to remand the rule without vacatur to preserve the environmental benefits of the rule. *North Carolina* v. *EPA,* 531 F.3d 896, *modified on reh'g,* 550 F.3d 1176 (DC Cir. 2008).

The action EPA is proposing would respond to the July and December 2008 opinions of the DC Circuit and correct the flaws in the CAIR methodology that were identified by the Court. The action responds to the Court's concerns in numerous ways. The methodology used to measure each state's significant contribution emphasizes air quality considerations and uses state specific data and information. The methodology also gives independent meaning to the interfere with maintenance prong of section 110(a)(2)(D)(i)(I). The state budgets for SO_2, annual NO_X and ozone season NO_X are directly linked to the measurement of each state's significant contribution and interference with maintenance. The compliance deadlines are coordinated with the attainment deadlines for the relevant NAAQS. And the proposed remedy includes assurance provisions to assure that all necessary reductions occur in each individual state.

The action would also propose FIPs which would replace the remanded CAIR FIPs. The proposed FIPs would apply to all states covered by the rule, including those for which EPA had previously approved SIPs under the remanded CAIR. If finalized as proposed, these FIPs would eliminate or, at a minimum, make measurable progress towards eliminating emissions of SO_2 and NO_X that significantly contribute to or interfere with maintenance of the 1997 and 2006 $PM_{2.5}$ NAAQS and the 1997 ozone NAAQS in the eastern half of the United States.

b. Address Transport Requirements With Respect to the Existing $PM_{2.5}$ Standards

This proposed rule is designed to address the requirements of section 110(a)(2)(D)(i)(I) of the CAA as they relate to the 1997 and 2006 $PM_{2.5}$ standards for states in the eastern United States. The proposed rule would both identify the emissions from states in the eastern U.S. that significantly contribute to nonattainment and interfere with maintenance of the NAAQS in downwind states, and prohibit such emissions.

States are obligated to submit SIPs to EPA addressing the provisions of section 110(a)(2), including the transport provisions of section 110(a)(2)(D)(i)(I), within 3 years of the promulgation of a new or revised NAAQS. For the 1997 NAAQS, these SIPs were due in 2000. On April 25, 2005 (effective May 25, 2005) EPA issued findings that states had failed to submit SIPs to satisfy the requirements of section 110(a)(2)(D)(i) of the Act under the 1997 ozone and $PM_{2.5}$ standards. 70 FR 21147, April 25, 2005. These findings started a 2-year clock for the promulgation of a FIP by EPA unless, prior to that time, each state makes a submission to meet the requirements of 110(a)(2)(D)(i) and EPA approves the submission. This 2-year period expired in May 2007. Because the Court found CAIR inadequate to satisfy the requirements of 110(a)(2)(D)(i)(I), neither EPA's FIP implementing the requirements of CAIR nor any states SIPs that relied on CAIR to satisfy the requirements of this section, are adequate to meet the requirements of section 110(a)(2)(D)(i)(I). EPA's obligation to issue a FIP has therefore not yet been met. The requirements of the FIPs proposed in this rule are designed to address this obligation.

Revisions to the 1997 $PM_{2.5}$ standards were signed by the Administrator on September 21, 2006, and published in the **Federal Register** on October 17, 2006. 71 FR 61144. The revisions were effective December 18, 2006. EPA interprets the 3 year deadline for submission of 110(a)(2) SIPs to be 3 years from the date of signature. Accordingly, for the 2006 revisions to the $PM_{2.5}$ NAAQS, the SIPs under 110(a)(2) were due on September 21, 2009. On June 9, 2010, EPA issued a notice making findings that states had not submitted SIPs under the 2006 $PM_{2.5}$ NAAQS by the September 2009 deadline. 75 FR 32673. These findings started a 2-year clock for the promulgation of a FIP by EPA unless, prior to that time, each state makes a submission to meet the requirements of 110(a)(2)(D)(i)(I) and EPA approves the submission. This 2-year period will expire on July 9, 2012. This proposal is designed to provide FIPs for the 2006 standards to ensure that the 110(a)(2)(D)(i)(I) obligation is fully satisfied as it relates to those standards. EPA also notes that under FIPs, reduction requirements are immediately effective and thus FIPs provide for the most expeditious means to implement emissions reduction requirements.

c. Address Transport Requirements With Respect to the 1997 Ozone Standards

This proposed rule, in concert with other actions, largely eliminates upwind state emissions that contribute significantly to nonattainment in, or interfere with maintenance by, any other state with respect to the 1997 8-hour ozone NAAQS. EPA will issue a subsequent proposal for the 1997 8-hour ozone NAAQS to address fully the requirements of CAA Section 110(a)(2)(D)(i)(I). EPA's goal is to fully address transport requirements for the 1997 ozone standards as soon as possible.

d. Provide for a Smooth Transition From Existing Programs

In addressing the Court remand in a way that satisfies the CAA transport requirements, EPA is also mindful of the need to ensure a smooth transition from the existing requirements. Substantial improvements in air quality have resulted from those requirements with associated health benefits. It is important not to lose those benefits as the new requirements move forward. It is also important to move quickly with those portions of the new requirements that provide the greatest benefits.

2. Key Guiding Principles

a. Appropriately Identify Necessary Upwind Reductions

Emissions from upwind states can, alone or in combination with local emissions, result in air quality levels that exceed the NAAQS and jeopardize the health of residents in downwind communities. Each upwind state is required by the "good neighbor provision" to eliminate its individual significant contribution to downwind state nonattainment and to eliminate emissions that interfere with downwind states" maintenance of the air quality standards. The Act does not require upwind states to eliminate all emissions that affect downwind air quality or shift responsibility for attaining the NAAQS to the upwind states. Instead, the "good neighbor provision" requires each upwind state to, within 3 years of promulgation or revision of a NAAQS, submit a SIP to prohibit those emissions that significantly contribute to nonattainment or interfere with maintenance downwind. The prohibition on these emissions is intended to assist downwind states as they design strategies for ensuring that the NAAQS are attained and maintained.

In practice, it is very complex for individual states to address the transport requirements. Generally for transport of ozone, and for transport of sulfate and nitrate fine particles, each downwind area is affected by emissions from multiple upwind states. In addition, in many cases states are simultaneously both upwind and downwind of one another. Further, only emissions that will significantly contribute to nonattainment or interfere with maintenance in another state are prohibited. Thus, an upwind state's obligations are affected by the air quality downwind. Downwind air quality, in turn, is affected by both local emissions and the cumulative impact of emissions from all of the contributing upwind states.

The problem of interstate transport is thus extremely complex and any remedy must acknowledge the inherent complexity of the problem. It is appropriate for EPA in developing such a remedy to be mindful of the interaction between upwind emissions controls and local emissions controls.

The EPA continues to conclude, as it did in developing the CAIR, that it would be difficult if not impossible for many nonattainment areas to reach attainment through local measures alone, and EPA finds no information developed subsequent to development of CAIR to alter this conclusion. At the time of the proposed CAIR rule, EPA conducted a local measures analysis representing an ambitious set of measures and emissions reductions that may in fact be difficult to achieve in practice. (Ref: Section IX of Technical Support Document for the Interstate Air Quality Rule Air Quality Modeling Analyses, January 2004). This analysis was intended to provide illustrative examples of the nature of location measures and possible reductions. This analysis was not intended to precisely identify local emissions control measures that may be available in a particular area. The EPA continues to believe that a strategy based on adopting cost effective controls on sources of transported pollutants as a first step will produce a more reasonable, equitable, and optimal strategy than one beginning with local controls. The local measures analyses we conducted were not, however, intended to develop a specific or "optimal" regional and local attainment strategy for any given area. Rather, the analysis was intended to evaluate whether, in light of available local measures, it is likely to be necessary to reduce significant regional transport from upwind states. EPA continues to believe that the two local measures analyses that were conducted for the CAIR strongly support the need for regional reductions of SO_2 and NO_X.

In conclusion, EPA believes that the proposed rule represents the best approach for identifying upwind state emissions that significantly contribute to nonattainment in, or interfere with maintenance by, downwind states.

b. Ensuring That Pollution Controls Operate

The proposed Transport Rule would, by 2012, cap emissions of SO_2 and NO_X on a state-by-state basis and guarantee that existing and planned pollution controls operate. EPA is convinced that the considerable benefits to air quality and public health that have been achieved must be ensured going forward. Keeping emissions of SO_2 and NO_X from increasing by 2012 in 27 states and DC assures that recent gains are maintained and that states that significantly contribute to downwind $PM_{2.5}$ nonattainment and maintenance areas do not increase their contribution to those areas. Further, this proposal would maintain the ozone season emissions reductions achieved since 2005 in 26 states, ensuring that states that significantly contribute to downwind ozone nonattainment and maintenance areas do not increase their contribution to those areas. Tables III.A–2 and III.A–3 in section III.A, previously, show the projected EGU emissions for the 2012 phase of the Transport Rule.

c. Provide Workable Approach for EPA and States

Another important goal in developing the proposed requirements is to provide requirements that can, as a practical matter, be implemented by both EPA and state air quality agencies. Both EPA and state resources are limited and EPA recognizes the importance of developing requirements that make efficient use of limited EPA and state resources. EPA also notes that the air quality improvements brought about by reducing transport can greatly assist states in the development of SIPs and attainment demonstrations.

d. Ensure a Reliable Power Supply

EPA recognizes that requirements for EGUs must be mindful of the variability in the operation of the power grid, and that any requirements for broad reductions should be structured in a way that ensures a reliable power supply.

e. Provide for Cost-Effectiveness

EPA believes that is important to keep both cost-effectiveness and air quality objectives in mind in addressing the CAA transport requirements.

f. Provide Incentives and Flexibility to the Regulated Community

EPA seeks to provide approaches that provide regulated owners/operators of sources with the incentive to achieve all cost-effective reductions. EPA's experience shows that providing this incentive, and the flexibility to seek alternatives to less cost-effective controls, provides for greater environmental protection at reduced cost.

D. Why does this proposed rule focus on the eastern half of the United States?

For this proposal, we identified a 37 state region for the technical analysis, including all states east of the Rockies, from the Dakotas through Texas eastward. Western states also need to address the requirements of section 110(a)(2)(D)(i)(I) of the CAA. However, the transport issues in the eastern United States are analytically distinct and this rule focuses only on that subset of the 110(a)(2)(D)(i)(I) issues.

First, interstate transport of $PM_{2.5}$ and ozone is a substantial and critical component for attaining the ozone and $PM_{2.5}$ NAAQS in the eastern United States. The significant reductions in ambient air pollutant concentrations since CAIR, due largely to the large reductions in transported emissions, only serve to reinforce this point.

Second, in developing the CAIR, EPA found that interstate transport (particularly for anthropogenic emissions) made much smaller contributions to exceedances of the 1997 $PM_{2.5}$ standards in the western United States. At the time, the only exceedances of the 15 $\mu g/m^3$ in those states were in parts of California, and in Lincoln County (Libby), Montana. The Montana location has subsequently come into attainment.

Technical information developed for EPA's recently completed nonattainment designations suggests that interstate emissions transport makes a relatively small contribution to exceedances in the western United States under the 2006 $PM_{2.5}$ standards. For these designations, EPA identified several locations in the western U.S. with exceedances of the 24-hour $PM_{2.5}$ standards. These locations were in California and a few other western states: Alaska, Washington, Oregon, Utah, and Arizona. Technical support information describing the nature of the 24-hour $PM_{2.5}$ problem at each of these locations is available at: *http://www.epa.gov/pmdesignations/2006standards/tech.htm.* A review of this information suggests to EPA that the Western nonattainment problems are relatively local in nature with limited interstate transport. EPA requests comment on this assessment.

E. Anticipated Rules Affecting Power Sector

On January 12, 2010, the EPA Administrator outlined seven priorities for the Agency. One of them is to improve air quality. In her description of this priority she said, "EPA will develop a comprehensive strategy for a cleaner and more efficient power sector, with strong but achievable reduction goals for SO_2, NO_X, mercury, and other air toxics." In furtherance of this priority goal, and to respond to statutory and judicial mandates, EPA is undertaking a series of regulatory actions over the course of the next 2 years that will affect the power sector in particular.

The rules under the CAA will substantially reduce the emissions of SO_2, NO_X, mercury, and other air toxics. To the extent that the Agency has the legal authority to do so while fulfilling its obligations under the Act and other relevant statutes, the Agency will also coordinate these utility-related air pollution rules with upcoming regulations for the power sector from EPA's Office of Water (OW) and its Office of Resource Conservation and Recovery (ORCR). EPA expects that this comprehensive set of requirements will yield substantial health and environmental benefits for the public, benefits that can be achieved while maintaining a reliable and affordable supply of electric power across the economy. In developing and promulgating these rules, the Agency will be providing the power industry with a much clearer picture of what EPA will require of it in the next decade. In addition to promulgating the rules themselves, the Agency will engage with other federal, state and local authorities, as well as with stakeholders and the public at large, with the goal of fostering investments in compliance that represent the most efficient and forward-looking expenditure of investor, shareholder, and public funds, resulting, in turn, in the creation of a clean, efficient, and completely modern power sector.

The major CAA rules that will drive these compliance investments are: (1) This transport rule; (2) potential future rules that may be needed to address transport under future revised ozone or fine particle health standards; (3) the

CAA Section 112(d) standards; (4) revisions to the NSPS for coal and oil-fired electric utility steam generating units; and (5) BART requirements and other requirements that address visibility and regional haze. Within the planning and investment horizon for compliance with these rules, the EPA very likely will be compelled to respond a pending petition to set standards for the emissions of greenhouse gases from steam electric generating units under the NSPS program. Furthermore, as set forth in the recently promulgated reinterpretation of the Johnson Memo, beginning in 2011 new and modified sources of GHG emissions, including EGUs, will be subject to permits under the Prevention of Significant Deterioration program requiring them to adopt BACT for their GHGs. Finally, EPA will also pursue with other federal agencies, states, and other groups energy efficiency improvements in the use of electricity throughout the economy that will contribute to additional environmental and public health improvements that the Agency wants to provide while lowering the costs of realizing those improvements.

A brief explanation of these major CAA rulemakings and activities follows.

Transport Rule. This proposed transport rule includes emissions reductions requirements for EGUs to address interstate transport under the 1997 ozone NAAQS, the 1997 $PM_{2.5}$ NAAQS, and the 2006 $PM_{2.5}$ NAAQS. After considering public comments on this proposal, EPA will endeavor to issue a final rule in spring 2011.

Rules to Address Transport under Revised Air Quality Health Standards. EPA currently is reconsidering its 2008 national ambient air quality standards for ozone, and is conducting a periodic review of the particulate matter NAAQS, including the fine particle standards. The Act requires EPA to ensure that primary standards are requisite to protect public health with an adequate margin of safety, and to set secondary standards requisite to protect public welfare. The Act requires EPA to review, and revise if appropriate, the primary and secondary NAAQS on a 5-year schedule to ensure that air quality standards reflect the latest scientific information on health and welfare effects. When air quality standards are set or revised, the Act requires revision of SIPs to ensure that these standards to protect public health and welfare are met expeditiously and, in the case of the health-based standards, within timetables in the Act.

If more protective NAAQS are promulgated, further emissions reductions would likely be needed in states where pollution levels exceed air quality standards, and in upwind states with emissions that significantly contribute to the air quality problems in another state. This may result in additional emission reduction requirements for facilities in the power sector, as well as for other sectors. The reconsideration of the March 2008 ozone air quality standards will be completed soon, and the review of particulate matter air quality standards by October 2011. SIP deadlines and attainment deadlines would flow from those dates.

EPA plans to make expeditious determinations of upwind state emissions reduction responsibilities for NAAQS for which interstate transport is an issue. This approach will lead to earlier emissions reductions to protect public health, as well as provide other benefits. In the *North Carolina* decision, the court made clear that downwind state nonattainment deadlines are legally relevant to the timing of reductions under section 110(a)(2)(D). Thus, expeditious determinations of upwind state responsibilities under section 110(a)(2)(D) can promote upwind reductions in time to help downwind states meet attainment deadlines, enable states and EPA to provide sources with earlier information on their emission reduction responsibilities, and maximize sources lead time to reduce emissions.

If a more protective ozone NAAQS is issued in August, EPA would plan to propose an interstate pollution transport rule for that NAAQS in 2011. We would expect work on that proposal to proceed in parallel with efforts to finalize this Transport Rule for the 1997 and 2006 NAAQS. A final rule to address interstate pollution transport for a reconsidered ozone NAAQS would be anticipated in 2012. In view of the implementation schedule for a reconsidered ozone NAAQS, compliance dates would be later than the compliance dates proposed for this Transport Rule, and would take into account attainment dates for that NAAQS and other factors such, as control cost and installation time. For any revised $PM_{2.5}$ NAAQS, EPA plans to conduct a similarly expeditious analysis of interstate transport to support a determination as to whether or not further emissions reductions from the power sector are required under section 110(a)(2)(D), in light of the emissions reductions required by other power sector rules.

A revised SO_2 NAAQS was issued on June 2 creating a new 1-hour SO_2 NAAQS which, when implemented, will protect Americans from asthma and respiratory difficulties associated with short term exposures to SO_2. Although EPA does not expect peak SO_2 levels to be a long-range transport issue, power plants are among the sources that can contribute to peak SO_2 levels and will likely be evaluated by states as they consider control measures to attain the new standards. Anticipated emissions reductions from power plants and other SO_2 sources under other Clean Air Act (CAA or Act) requirements (*e.g.*, transport rules, and MACT standards) are expected to play a significant role in attainment of the 1-hour SO_2 NAAQS.

Section 112(d) Standards for Utility Units. In 2008, the DC Circuit Court vacated the CAMR and the 112(n) Revision Rule, which removed coal- and oil-fired electric utility steam generating units from the section 112(c) list of sources subject to regulation. EPA is in the early stages of developing regulations under section 112 of the CAA that will require existing and new coal- and oil-fired utility units to meet emissions limits for mercury and other HAPs emitted from these sources. As required by section 112, EPA will issue a set of emissions standards. In part, the section 112(d) rule will require that all existing major sources achieve the emission limits for HAPs which will be at least as stringent as the average emissions reduction currently achieved by the best performing 12 percent of these units. Additionally, any new major source will be required to meet emission limits that are at least as stringent as what is currently achieved by the best-performing single source. Currently, the Agency is seeking data on five categories of HAP emissions: (1) Acid gases (*e.g.*, hydrochloric acid, hydrogen fluoride, and hydrogen cyanide); (2) mercury; (3) Non-Hg metals (*e.g.*, lead, cadmium, selenium, and arsenic); (4) dioxins/furans; and, (5) other organic hazardous air pollutants. EPA expects to receive the requested data, including stack testing results, by September 2010. EPA has agreed to sign the proposed rule by March 16, 2011, and sign the final rule no later than November 16, 2011. EPA may provide existing sources up to 3 years to comply with section 112(d) standards, and the CAA authorizes the permit authority to grant a 1 year extension of the compliance date on a case-by-case basis if such extension is necessary for the installation of controls. The CAA requires new sources to comply on the effective date of the final rule or at startup, whichever is later. If EPA were to provide 3 years for compliance with the section 112(d) standards, compliance would generally be required by early 2015.

In developing these rules, EPA will endeavor to proceed in a way that provides all stakeholders and other Federal, State and local decision-makers with ongoing, up-to-date information about the full suite of environmental responsibilities that the power sector must undertake. This, in turn, will enable power companies and others whose policies and decisions affect their investment choice to adopt compliance strategies that take full advantage of co-control opportunities and efficiencies and other approaches to maximizing the cost-effectiveness and leveraging benefits of their investments.

New Source Performance Standards. NSPS are administered under section 111 of the CAA. The standards for new, modified, and reconstructed steam EGUs are contained in 40 CFR part 60 subpart Da, which was last amended in 2006. The current structure of subpart Da sets output-based (*i.e.*, lbs of emission/MWh) emission limits for NO_X and SO_2 and optional output-based standards for particulate matter. EPA is currently re-evaluating the standards in Subpart Da to determine whether they reflect the degree of emission limitation achievable through the application of the best system of emission reduction, which the Administrator determines has been adequately demonstrated. EPA also has a pending voluntary remand to decide whether NSPS standards for this source category should include limits on GHG emissions. EPA is considering the timetable for these actions and decisions in light of legal obligations and policy considerations, including the desirability of the industry knowing its regulatory obligations to inform investment decisions.

Regional Haze/BART. States are required to develop SIPs that address regional haze in scenic areas such as national parks and wilderness areas. EPA regulations for regional haze appear in Chapter 40 of the CFR in sections 51.308 and 51.309. One of the requirements of the regional haze SIPs is to provide for BART for large industrial sources including EGUs. The BART provisions affect EGUs put into operation between 1962 and 1977.

Energy Efficiency. Policies that will promote efficient use of electric power can be an integral, highly cost-effective component of power companies" compliance strategies. Reducing demand for electricity can in itself achieve large emissions reductions and public health benefits, while enhancing the reliability of the grid. It can also lower the cost of emissions reductions for consumers of electricity and for the power industry, as investments are avoided in unnecessary infrastructure.

EPA does not have sole responsibility for the development of energy policy to promote efficiency. To facilitate this component of the power sector's compliance strategy, EPA intends to engage with other federal, state, and local agencies whose policies and actions can make it easier for power companies to adopt, or benefit from, energy efficiency investments in their compliance strategies. EPA will continue to use its authorities to advance energy efficiency by providing incentives for energy efficiency in our regulatory programs (*e.g.*, output-based standards) and through our successful existing voluntary programs such as ENERGY STAR. The Department of Energy (DOE) also has considerable resources to encourage efficient use of electricity. Additional resources have been made available under the American Recovery and Reinvestment Act to both DOE and EPA to promote energy efficiency. State governments, both in their environmental programs and through their public service commissions, which regulate electric utility rates, can promote energy efficiency. Many state governments have been leaders in promoting efficient use of electricity through such mechanisms as energy efficiency standards and demand response, and EPA and DOE are assisting state governments in this effort. Local governments as well, through building codes, zoning, and other actions, can and do promote end-use energy efficiency. The Federal Energy Regulatory Commission (FERC) regulates wholesale electricity markets and sets mandatory reliability standards to assure a safe reliable power system. In carrying out this mission FERC recognizes that energy efficiency is a resource, to be considered along with other energy resources in reliability and economic planning.

All of these entities will need to work in concert to achieve a truly efficient, reliable, cost-effective electric power system. EPA is committed to meeting this challenge.

Non-Air Office Regulations. EPA is also working on three additional rules that will have potential impacts on the power sector. The Office of Solid Waste and Emergency Response is developing revised regulations for coal combustion residues, which are the combustion byproducts associated with the use of coal as a fuel. The Administrator signed the proposed rule on May 4, 2010. Over the next few years, EPA's Office of Water plans to develop two rules affecting electric generating units; the precise timing of these rules is being determined. One will regulate cooling water intake structures. The other will revise the effluent guidelines for wastewater discharges from power plants. Each of these rules has cost implications to the power sector, and the Agency intends to coordinate these regulations with the upcoming air regulations. We intend to maximize reductions in pollution while maintaining cost-effective solutions.

As a first step to carrying out its commitment to promote and facilitate the most cost-effective and forward-looking compliance investments and strategies on the part of the power sector, EPA will conduct extensive outreach concerning the full range of the upcoming environmental responsibilities of the sector as it proposes the Transport Rule. Upon this proposal, the Agency will begin an outreach effort with the public, the regulated community, state air regulators, and others to (1) describe the Transport Rule proposal, and (2) provide information on the 2011 section 112 standards for utility units and other upcoming EPA rulemakings affecting the power sector. The intent will be to inform all stakeholders of the industry's obligations and opportunities for the industry to use investments in SO_2 and NO_X reductions to help smooth transition to compliance with the Section 112(d) standards applicable to utility units.

At the same time EPA also intends to expand its outreach to others—who can play a significant role in promoting or requiring investment in energy efficiency. EPA intends to continue these efforts over time as more information becomes available in the development of the various rulemakings under development for the power sector.

IV. Defining "Significant Contribution" and "Interference With Maintenance"

This section describes EPA's proposed approach to define emissions that significantly contribute to nonattainment or interfere with maintenance of the $PM_{2.5}$ and ozone NAAQS downwind. The section begins by providing background on how "significant contribution" and "interference with maintenance" were defined in the past by EPA for the NO_X SIP Call and the CAIR, describing past Court opinions on EPA's approach, and presenting an overview of EPA's proposed Transport Rule approach (section IV.A). Next, section IV.B describes the proposed approach to identify upwind contributing states. Section IV.C details the air quality modeling approach and results used for this proposed rule. Section IV.D provides a detailed description of EPA's proposed approach to quantify emissions that significantly contribute and interfere with maintenance. Section IV.E includes proposed state emissions budgets before accounting for the inherent variability in power system operations. Section IV.F discusses the inherent variability in power system operations, proposes variability limits on the state budgets, and presents projected emissions reduction results. Section IV.G describes how the proposed approach is consistent with judicial opinions. Finally, section IV.H lists alternative approaches to defining significant contribution and interference with maintenance that EPA evaluated but is not proposing.

A. Background

1. Approach Used in NO_X SIP Call and the CAIR

a. Significant Contribution

Two rules EPA promulgated that address interstate transport of pollutants are the NO_X SIP Call (63 FR 57356; October 27, 1998) and the CAIR (70 FR 25162; May 12, 2005), which are described in section III.B. In both of these rules, EPA used a 2-step approach to quantify significant contribution. The approaches used in both rules were similar.

In the first step, EPA applied an air quality threshold to determine a set of upwind states whose potential for significant contribution should be evaluated further. That is, EPA compared the contributions that individual upwind states make to downwind receptors and identified states whose contributions were greater than the specified threshold amount. EPA referred to these states as significant contributors but did not rely on this first step to quantify or measure the states' significant contribution.

In the second step, EPA determined the quantity of emissions that the states collectively could remove using highly cost-effective controls. EPA defined this quantity of emissions as the "significant contribution." The approach used in each rule is described in more detail, later.

NO_X SIP Call. EPA addressed the section 110(a)(2)(D)(i)(I) requirement to prohibit emissions that significantly contribute to downwind nonattainment in the NO_X SIP Call. To do so, EPA developed a methodology for identifying emissions that constitute upwind states' "significant contribution." EPA determined that emissions "contribute" to nonattainment downwind if they have an impact on nonattainment downwind (62 FR 60325). EPA established several criteria or factors for the "significant contribution" test (and further indicated that the same criteria should apply to the "interfere with maintenance" provision).[14]

EPA determined the amount of emissions that significantly contribute to downwind nonattainment from sources in a particular upwind state 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 (63 FR 57403).

Air Quality Factor. The first factor that EPA used to determine the amount of emissions that significantly contribute to downwind nonattainment was the air quality factor, consisting of an evaluation of the impact on downwind air quality of the upwind state's emissions.

EPA specifically considered three air quality factors with respect to each upwind state:

- 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; and
- The ambient impact of the emissions from the upwind state's sources on the downwind nonattainment problems (63 FR 57376).

EPA explained the first factor, collective contribution, by noting,

> [V]irtually every nonattainment problem is caused by numerous sources over a wide geographic area * * * [. This] factor suggest[s] 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 immeasurable ambient impact by itself (63 FR 57377).

The second air quality factor is the extent of downwind nonattainment problems. EPA considered the then-current air quality of the area, the predicted future air quality (assuming implementation of required controls but not the transport requirements that were the subject of the NO_X SIP Call), and, when air quality designations had already been made, the boundaries of the area in light of designation status (63 FR 57377).[15]

EPA applied the third air quality factor by projecting the amount of the upwind state's entire inventory of anthropogenic emissions to the year 2007, and then quantifying the impact of those emissions on downwind nonattainment through the appropriate air quality modeling techniques.[16] Specifically, (i) EPA determined the minimum threshold impact that the upwind state's emissions must have on a downwind nonattainment area to be considered potentially to contribute significantly to nonattainment; and then (ii) for states with impacts above that threshold, EPA developed a set of metrics for further evaluating the contribution of the upwind state's emissions on a downwind nonattainment area (63 FR 57378). EPA referred to states with emissions that had a sufficiently great impact as significant contributors; however, the precise amount of their significant contribution was not calculated until the next step. Because the ozone problem is caused by many relatively small contributions, even relatively small contributors must participate in the solution. For this reason, EPA determined that even a relatively small contribution can be significant contribution given the nature of the problem, and established relatively low thresholds.

Cost Factor. The cost factor is the second major factor that EPA applied to determine the significant contribution to nonattainment: "EPA * * * 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" (63 FR 57377). Applying this cost factor on top of the air quality factor, EPA determined that emissions that both were from states that exceeded

[14] In the NO_X SIP Call, because the same criteria applied, the discussion of the "contribute significantly to nonattainment" test generally also applied to the "interfere with maintenance" test. However, in the NO_X SIP Call, EPA stated that the "interfere with maintenance" test applied with respect to only the 8-hour ozone NAAQS (63 FR 57379–80).

[15] EPA explained in the NO_X SIP Call, "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." (63 FR 57375, footnote 25)

[16] Although EPA's air quality modeling techniques examined all of the upwind state's emissions of ozone precursors (including VOC and NO_X), only the NO_X emissions had meaningful interstate impacts.

the air quality thresholds and could be eliminated through the application of highly cost-effective controls constituted a given state's significant contribution.

Choice of Highly Cost-Effective Standard. EPA chose the standard of "highly cost-effective" in order to assure state flexibility in selecting control strategies to meet the emissions reduction requirements of the rulemaking. That is, the rulemaking required the states to achieve specified levels of emissions reductions—the levels achievable if states implemented the control strategies that EPA identified as highly cost-effective—but the rulemaking did not mandate those highly cost-effective control strategies, or any other control strategy. Indeed, in calculating the amount of the required emissions reductions by assuming the implementation of highly cost-effective control strategies, EPA assured that other control strategies—ones that were cost-effective, if not highly cost-effective—remained available to the states.

Determination of Highly Cost-Effective Amount. EPA determined the dollar amount considered to be highly cost-effective by reference to the cost-effectiveness of recently promulgated or proposed NO_X controls. EPA determined that the average cost-effectiveness of controls ranged up to approximately $1,800 per ton of NO_X removed (1990$) on an annual basis. The EPA considered the controls in the reference list to be cost-effective.

EPA established $2,000 per ton (1990$) in average cost-effectiveness for summer ozone season emissions reductions as, at least directionally, the highly cost-effective amount. Identifying this amount on an ozone season basis was appropriate because the NO_X SIP Call concerned the ozone standard, for which emissions reductions during only the summer ozone season are necessary. In determining the highly cost-effective amount, EPA analyzed costs on a regionwide basis, and assumed a cap and trade program for EGUs and large non-EGU boilers and turbines.

Source Categories. EPA then determined that the source categories for which highly cost-effective controls were available included EGUs, large industrial boilers and turbines, and cement kilns. At the same time, EPA determined, for those source categories, the level of emissions reductions in each state that would result from the application of all controls that would be highly cost-effective and that would be feasible. The EPA considered other source categories, but found that highly cost-effective controls were not available for various reasons, including the size of the sources, the relatively small amount of emissions from the sources, or the control costs.

Other Factors. EPA also relied on several other, secondary considerations to identify the required amount of emissions reductions. The first concerned the consistency of regional reductions with downwind attainment needs. The second general consideration was "the overall fairness of the control regimes" to which the downwind and upwind areas were subject. The third general consideration was "general cost considerations." The EPA noted that "in general, areas that currently have, or that in the past have had, nonattainment problems * * * have already incurred ozone control costs." The next set of controls available to these nonattainment areas would be more expensive than the controls available to the upwind areas. The EPA found that this cost scenario further confirmed the reasonableness of the upwind control obligations (63 FR 57379).

In the NO_X SIP Call, EPA considered all of these factors together in determining the level of controls considered to be highly cost-effective. Within the region, the nonattainment areas already had implemented required VOC and NO_X controls that covered much of their inventory. However, the upwind states in the region generally had not implemented such controls (except as needed to address their ozone nonattainment areas). In this context, EPA considered it reasonable to impose an additional control burden on the upwind states. Air quality modeling showed that residual nonattainment remained even with this additional level of upwind controls so that further reductions from downwind and/or upwind areas would be necessary.

After ascertaining the controls that qualified as highly cost-effective, EPA developed a methodology for calculating the amount of NO_X emissions that each state was required to reduce on grounds that those emissions contribute significantly to nonattainment downwind. The total amount of required NO_X emissions reductions was the sum of the amounts that would be reduced by application of highly cost-effective controls to each of the source categories for which EPA determined that such controls were available (63 FR 57378).

Electric Generating Units. The largest of the source categories discussed previously was EGUs. EPA determined the amount of reductions associated with EGU controls by applying the control rate that EPA considered to reflect highly cost-effective controls to each state's EGU heat input (adjusted for projected growth) (70 FR 25173.) In the NO_X SIP Call, EPA evaluated the costs of control on a region-wide basis.

CAIR. In the CAIR, EPA again addressed the section 110(a)(2)(D)(i)(I) requirement to prohibit emissions that significantly contribute to downwind nonattainment (70 FR 25162). While the NO_X SIP Call had addressed significant contribution with respect to the 1997 ozone NAAQS, the CAIR addressed significant contribution with respect to both the ozone and annual $PM_{2.5}$ NAAQS promulgated in 1997. In the CAIR, EPA used a methodology to identify states" significant contribution based on and very similar to the methodology used in the NO_X SIP Call.

To quantify the amounts of emissions that contribute significantly to nonattainment, EPA explained in the CAIR that the Agency primarily focused on the air quality factor reflecting the upwind state's ambient impact on downwind nonattainment areas, and the cost factor of highly cost-effective controls. *See* 70 FR 25174.

Air Quality Factor—$PM_{2.5}$. EPA employed air quality modeling techniques to assess the impact of each upwind state's entire inventory of anthropogenic SO_2 and NO_X emissions on downwind nonattainment and maintenance for the annual $PM_{2.5}$ NAAQS.[17] EPA determined that upwind NO_X and SO_2 emissions contribute significantly to annual $PM_{2.5}$ nonattainment as of the year 2010.

As in the NO_X SIP Call, EPA used a 2-step approach to quantify significant contribution. In the CAIR, in the first step EPA adopted a threshold air quality impact of 0.2 μg/m3 for $PM_{2.5}$. An upwind state with contributions to downwind nonattainment below this level would not be subject to regulatory requirements, but a state with contributions at or higher than this level would be subject to further evaluation (70 FR 25174–75).

This level reflects the fact that $PM_{2.5}$ nonattainment, like ozone, is caused by many sources in a broad region and therefore may be solved only by controlling sources throughout the region. As with the NO_X SIP Call, the collective contribution condition of $PM_{2.5}$ air quality is reflected in the relatively low threshold (70 FR 25175).

Air Quality Factor—8-Hour Ozone. EPA employed air quality modeling techniques to assess the impact of each upwind state's inventory of NO_X and VOC emissions on downwind nonattainment. The EPA determined

[17] EPA did not address 24-hour $PM_{2.5}$ NAAQS in CAIR, only the annual $PM_{2.5}$ NAAQS.

that upwind NO_X emissions contribute significantly to 8-hour ozone nonattainment as of the year 2010. Therefore, EPA projected NO_X emissions to the year 2010, assuming certain required controls (but not controls required under the CAIR), and then modeled the impact of those projected emissions on downwind 8-hour ozone nonattainment in that year (70 FR 25175).

EPA used the same threshold amounts and metrics for 8-hour ozone that it used in the NO_X SIP Call. That is, emissions from an upwind state were found to contribute significantly to nonattainment if the maximum contribution was at least 2 parts per billion, the average contribution greater than one percent, and certain other numerical criteria were met. EPA also evaluated frequency, magnitude, and relative amounts of contribution to determine which linkages were significant before costs were considered.

Cost Factor. The second step in the 2-step process is to apply the cost factor. As in the NO_X SIP Call, EPA interpreted this factor as mandating emissions reductions in amounts that would result from application of highly cost-effective controls. In the CAIR, EPA determined the level of costs that would be highly cost-effective on a regional basis by reference to the cost effectiveness of other recent controls. EPA concluded that EGUs were the only source category for which highly cost-effective SO_2 and NO_X controls were available at the time. EPA determined as highly cost-effective the dollar amount of cost-effectiveness that falls near the low end of a reference range of control costs. See 70 FR 25175. In the CAIR, as in the NO_X SIP Call, EPA analyzed the costs of control on a regionwide basis.

Other Factors. As with the NO_X SIP Call, EPA considered other factors that influence the application of the air quality and cost factors, and that confirm the conclusions concerning the amounts of emissions that upwind states must eliminate as contributing significantly to downwind nonattainment. See 70 FR 25175.

b. Interference With Maintenance

Section 110(a)(2)(D)(i)(I) requires that SIPs for national primary and secondary air quality standards contain adequate provisions prohibiting emissions in amounts that "interfere with maintenance by any other state" of any such standard.

In the NO_X SIP Call and in the CAIR, EPA gave the term "interfere with maintenance" a meaning much the same as the meaning given to the term "significant contribution." That approach, which was found inconsistent with the requirements of 110(a)(2)(D)(i)(I), is described later. EPA's proposed new approach to interpreting "interfere with maintenance" is described in section IV.D, later.

NO_X SIP Call: In the NO_X SIP Call, EPA explained its approach as follows (63 FR 57379–80):

> 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 notice of proposed rulemaking.

In addition, the NO_X SIP Call preamble stated:

> 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.

CAIR: In the CAIR, EPA also interpreted "interfere with maintenance" in a limited way. EPA only considered whether upwind state emissions eventually posed a maintenance problem for areas that EPA projected to be in nonattainment in 2010 (the year that was the focus of the analysis of significant contribution to nonattainment). EPA did not examine whether areas in attainment in 2010 might face a maintenance problem either in 2010 or thereafter, so no upwind state controls were considered to assist such areas with maintaining clean air. The CAIR preamble stated (70 FR 25193, footnote 45), "we believe the 'interfere with maintenance' prong may come into play only in circumstances where EPA or the state can reasonably determine or project, based on available data, that an [nonattainment] area in a downwind state will achieve attainment, but due to emissions growth or other relevant factors is likely to fall back into nonattainment." [18]

In responding to comments on the CAIR proposal, we also used this interpretation of the maintenance provision to help support the need for Phase II CAIR reductions. For ozone, we conducted an analysis that looked at (1) the amount by which receptor locations were projected to attain in 2015 and (2) the year-to-year variability in ozone levels due to weather and other factors based on a review of historical monitoring data. This analysis concluded that areas within 3–5 ppb of the standard, and sometimes greater (*e.g.*, Fulton County, Atlanta) had historic variability as great as 8 ppb, and that this variability suggests strongly that upwind states could be interfering with maintenance even if modeling shows attainment by up to these amounts. For $PM_{2.5}$, while we lacked historical data to support the same variability analysis, we characterized attaining the annual standard by 0.5 μg/m3 as "attaining by a narrow margin" thus giving rise to maintenance concerns, and noted that in past (mobile source) rules we had indicated that attainment by a margin of 10 percent or less could be considered to raise maintenance concerns.

2. Judicial Opinions

a. Significant Contribution

In *North Carolina* v. *EPA,* 531 F.3d. 896 (DC Cir. 2008), the Court held that the approach EPA used in CAIR to measure each state's significant contribution was insufficient. EPA, the Court concluded, had failed to "measure[ ] the significant contribution from sources within an individual state to downwind nonattainment areas." *Id.* at 907. The Court further reasoned that the lack of a state-specific significant contribution analysis made it impossible for EPA to show that the

[18] The CAIR final preamble stated: "EPA has evaluated the attainment status of the downwind receptors in 2010 and 2015, and has determined that each upwind state's 2010 and 2015 emissions reductions are necessary to the extent required by the rule because a downwind receptor linked to that upwind state will either (i) remain in nonattainment and continue to experience significant contribution to nonattainment from the upwind state's emissions; or (ii) attain the relevant NAAQS but later revert to nonattainment due, for example, to continued growth of the emissions inventory."

trading programs and state budgets established to implement the trading programs, effectuated the section 110(a)(2)(D)(i)(I) statutory mandate to eliminate emissions within the state that significantly contribute to nonattainment or interfere with maintenance in other states.

Specifically, the court rejected the regional scope of EPA's analysis. It reasoned that "because EPA evaluated whether its proposed emissions were 'highly cost effective' at the regionwide level assuming a trading program, it never measured the 'significant contribution' from sources within an individual state to downwind nonattainment areas." *Id.* at 907. In reaching this conclusion, however, the Court also recognized that aspects of EPA's methodology for analyzing significant contribution had been upheld in *Michigan* v. *EPA,* 213 F.3d 663 (DC Cir. 2000), and it left those holdings undisturbed. Specifically, the Court acknowledged its prior conclusion that "significance may include cost" *North Carolina,* 531 F.3d at 919 (citing *Michigan* 213 F.3d 677–79), and thus it is acceptable for EPA to use cost to "draw the 'significant contribution' line". *Id.* The Court also recognized that *Michigan* approved EPA's decision to apply a uniform emissions control requirement to all upwind states despite different levels of contribution. *See North Carolina,* 531 F.3d at 908. The Court thus concluded that while EPA must "measure each state's 'significant contribution' to downwind nonattainment" that measurement need not "directly correlate with each state's individualized air quality impact on downwind nonattainment relative to other upwind states." *Id.* at 908.

In *North Carolina,* the Court also upheld several aspects of the air quality modeling EPA used in the significant contribution analysis. It upheld EPA's use of whole state modeling, *see id.* at 923–26, and deferred to EPA's selection of the $PM_{2.5}$ contribution threshold, *see id.* at 914–15. With regard to EPA's application of the methodology to individual states, the Court found that EPA had failed to respond to comments by Minnesota Power alleging errors in the application of this methodology to determine Minnesota's contribution to downwind $PM_{2.5}$ nonattainment areas. *See id.* at 926–28.

b. Interference With Maintenance

In the CAIR case, the Court also rejected EPA's approach to the second prong of section 110(a)(2)(D)(i)(I), holding that EPA's failure to give independent meaning to the term "interfere with maintenance" was inconsistent with the statutory mandate. *See North Carolina,* 531 F.3d at 910. The Court rejected the approach used in CAIR reasoning that it "provides no protection for downwind areas that, despite EPA's predictions, still find themselves struggling to meet NAAQS due to upwind interference in 2010." *Id.* at 910–11.

3. Overview of Proposed Approach

In this section, EPA will explain how it proposes to identify which states are significantly contributing to downwind non-attainment and/or interfering with maintenance of the NAAQS at downwind sites and to quantify what that contribution is.

In this action, EPA is proposing to use a two step approach to measuring each state's significant contribution. The methodology used is based on the approach used in CAIR and the NO_X SIP Call but modified to address the concerns raised by the Court. In the first step of this proposed approach, EPA uses air quality modeling to quantify individual states' contributions to downwind nonattainment and maintenance sites in 2012. States whose contributions to any downwind sites are greater than 1 percent of the relevant NAAQS are considered "linked" to those sites for the purpose of the second step in the analysis. In the second step, EPA identifies the portion of each state's contribution that constitutes its "significant contribution" and "interference with maintenance." To do so, EPA uses maximum cost thresholds, informed by air quality considerations. Specifically, for each precursor pollutant (*i.e.,* SO_2 and NO_X for $PM_{2.5}$ and NO_X for ozone) emitted by the upwind states that EPA has identified as linked to NAAQS nonattainment and maintenance sites downwind, EPA identifies, through this process, the reductions available from EGUs in each individual upwind state at the appropriate maximum cost threshold. These emissions reductions are the amount of the upwind state's significant contribution. The cost thresholds used in this portion of the analysis, in contrast to the thresholds used in CAIR and the NO_X SIP Call, are informed by air quality considerations, in addition to a comparison of the cost of control in other regulatory contexts. Specific cost thresholds were developed for annual SO_2, annual NO_X, and ozone-season NO_X. Where appropriate, EPA developed higher and lower cost thresholds, based on the downwind air quality impact of emissions from different groups of states. Although EPA in the past has applied a uniform remedy to all states found to have a significant contribution, in this proposal EPA divides, for individual pollutants, the significantly contributing states into two groups: Those whose significant contribution can be eliminated at a lower cost threshold; and those whose significant contribution is not eliminated (to the extent that it has been identified in this proposal) until they reach the higher cost threshold. The lower cost threshold applies to a state if the reduction in emissions at that threshold eliminates nonattainment and maintenance problems at all "linked" sites.

EPA considers that the maintenance concept has two components: Year-to-year variability in emissions and air quality, and continued maintenance of the air quality standard over time. Both components of maintenance are addressed in this proposal.

Step One: Air Quality Analysis

In step one of this proposed approach, EPA analyzes emissions from 37 states to quantify the impact of those emissions on downwind nonattainment and maintenance sites in 2012 (*see* section IV.C for a detailed discussion of air quality modeling). To begin this analysis, EPA first identifies all monitors projected to be in nonattainment or, based on historic variability in air quality, projected to have maintenance problems in 2012. This baseline analysis takes into account emissions reductions associated with the implementation of all federal rules promulgated by December 2008 and assumes that the CAIR is not in effect. This baseline presents a unique situation. EPA has been directed to replace the CAIR; yet the CAIR remains in place and has led to significant emissions reductions in many states.

A key step in the process of developing a 110(a)(2)(D)(i)(I) rule involves analyzing existing (base case) emissions to determine which states significantly contribute to downwind nonattainment and maintenance areas. EPA cannot prejudge at this stage which states will be affected by the rule. For example, a state affected by CAIR may not be affected by the new rule and after the new rule goes into effect, the CAIR requirements will no longer apply. For a state covered by CAIR but not covered by the new rule, the CAIR requirements would not be replaced with new requirements, and therefore an increase in emissions relative to present levels could occur in that state. More fundamentally, the court has made clear that, due to legal flaws, the CAIR rule cannot remain in place and must be replaced. If EPA's base case analysis were to ignore this fact and assume that reductions from CAIR would continue indefinitely, areas that are in attainment solely due to controls required by CAIR would again face nonattainment problems because the existing protection from upwind pollution would not be replaced. For these reasons, EPA cannot assume in its base case analysis, that the reductions required by CAIR will continue to be achieved.

Following this logic, the 2012 base case shows emissions higher than current levels in some states. Because EPA has been directed to replace CAIR, EPA believes that for many states, the absence of the CAIR NO_X program will lead to the status quo of the NO_X Budget Program, which limits ozone-season NO_X emissions and ensures the operation of NO_X controls in those states. Also, without the CAIR SO_2 program, emission requirements in many areas would revert to the comparatively less stringent requirements of the Title IV Acid Rain Program. As a result, SO_2 emissions in many states would increase markedly in the 2012 base case relative to the present. Efforts to comply with ARP rules at the least-cost would occur in many cases without the operation of existing scrubbers through use of readily available, inexpensive Title IV allowances. Notably, all known controls that are required under state laws, NSPS, consent decrees, and other enforceable binding commitments through 2014 are accounted for in the base case. It is against this backdrop that the Transport Rule is analyzed and that significant contribution to nonattainment and interference with maintenance must be addressed.

Step Two: Quantifying Each State's Significant Contribution

In step two, EPA identifies the portion of each state's contributing emissions that constitute the emissions from that state that "significantly contribute to, or interfere with maintenance by" another state. To do so with respect to the 1997 ozone NAAQS, EPA analyzes the costs and associated air quality impacts of reductions in ozone-season NO_X. To do so with respect to the 1997 and 2006 $PM_{2.5}$ NAAQS, EPA analyzes the costs and associated air quality impacts of reductions in annual SO_2 and annual NO_X. The analysis uses cost thresholds, informed by air quality considerations and applied on a state specific basis. EPA considered a number of factors, including air quality and cost factors because the circumstances that lead to nonattainment and maintenance problems at downwind sites are extremely complex. By using both cost and air quality factors, EPA's analysis can address the different circumstances influencing the linkages between upwind and downwind states. As such, EPA believes it is appropriate to consider these factors in identifying the emissions that must be prohibited.

While we believe it is important to consider cost, we also recognize that we can't "just pick a cost for the region and deem 'significant' any emissions that sources can eliminate more cheaply." *North Carolina,* 531 F.3d at 918. In contrast to the approach used in CAIR and the NO_X SIP Call, the cost thresholds EPA uses in this proposed approach are informed by air quality considerations and applied on a state specific basis. EPA first develops state-specific costs curves showing what level of emissions reductions could be achieved at different cost levels in 2012 and 2014. EPA then uses a simplified air quality assessment tool to examine the impact of the reductions at specific cost levels on downwind nonattainment and maintenance sites. This approach allows EPA to identify specific cost breakpoints based on air quality considerations (such as the cost at which the air quality assessment analysis projects large numbers of downwind sites maintenance and nonattainment problems would be resolved) or cost criteria (such as being a cost where large emissions reductions occur because a particular technology is widely implemented at that cost). EPA then evaluated the reasonableness of the cost breakpoints using a number of criteria to determine which of the breakpoints appropriately represented a cost threshold with which to define significant contribution.

These thresholds are then applied on a state-specific basis to quantify each individual state's significant contribution.

The remainder of this section provides further detail on the specific methodology developed by EPA and the application of this methodology to identify emissions that significantly contribute to or interfere with maintenance of the 1997 ozone NAAQS and the 1997 and 2006 $PM_{2.5}$ NAAQS.

B. Overview of Approach To Identify Contributing Upwind States

This section describes EPA's proposal to require reductions in upwind emissions of SO_2 and NO_X to address $PM_{2.5}$ transport and to require reductions in upwind emissions of NO_X to address ozone-related transport. In addition, this section provides an overview of EPA's approach to identifying which states are subject to the proposed rule, and which states are not subject to the rule because their sources' emissions were found to not significantly contribute to nonattainment of the $PM_{2.5}$ or 8-hour ozone standards or interfere with maintenance of those standards, in downwind states.

The EPA assessed individual upwind states" 2012 projected ambient impacts on downwind nonattainment and maintenance receptors for a 37-state region in the eastern U.S., and established threshold values for $PM_{2.5}$ and ozone to identify those states whose impact does not constitute a significant contribution to air quality violations in the downwind states. EPA used these same threshold values in considering the potential for upwind state emissions to interfere with maintenance of the $PM_{2.5}$ and 8-hour ozone NAAQS in downwind areas. The EPA used air quality modeling of emissions in each state to estimate the ambient impacts. The air quality modeling platform and approach to quantifying interstate contributions to $PM_{2.5}$ and ozone are discussed in section IV.C.

As noted previously, EPA considers that the maintenance concept has two components: Year-to-year variability in emissions and air quality, and continued maintenance of the air quality standard over time. The way that EPA defined maintenance based on year-to-year variability is discussed in section IV.C., and directly affects the proposed requirements of this rule. EPA also considered whether further reductions were necessary to ensure continued lack of interference with maintenance of the NAAQS over time. EPA concluded that in light of projected emission trends, and also considering the emissions reductions from this proposed rule, no further reductions are required solely for this purpose at PM and ozone receptors for which we are partially or fully determining significant contribution for the current NAAQS. (*See* discussion of emissions trends in Chapter 7 of TSD entitled "Emission Inventories," included in the docket for this proposal.)

1. Background

a. For the CAIR, how did EPA determine which pollutants were necessary to control to address interstate transport for $PM_{2.5}$?

Section II of the January 2004 CAIR proposal summarized key scientific and technical aspects of the occurrence, formation, and origins of $PM_{2.5}$, as well as findings and observations relevant to formulating control approaches for reducing the contribution of transport to fine particle problems (69 FR 4575–87). Key concepts and provisional conclusions drawn from this discussion were summarized as follows in the preamble to the final CAIR:

(1) Fine particles (measured as $PM_{2.5}$ for the NAAQS) consist of a diverse mixture of substances that vary in size, chemical composition, and source. The $PM_{2.5}$ includes both "primary" particles that are emitted directly to the atmosphere as particles, and "secondary" particles that form in the atmosphere through chemical reactions from gaseous precursors. The major components of fine particles in the eastern U.S. can be grouped as follows: Carbonaceous material (including both primary and secondary organic carbon and black carbon); sulfates; nitrates; ammonium; and crustal material, which includes suspended dust as well as some other directly emitted materials. The major gaseous precursors of $PM_{2.5}$ include SO_2, NO_X, NH_3, and certain volatile organic compounds.

(2) Examination of urban and rural monitors indicate that in the eastern U.S., sulfates, carbonaceous material, nitrates, and ammonium associated with sulfates and nitrates are typically the largest components of transported $PM_{2.5}$, while crustal material tends to be only a small fraction.

(3) Atmospheric interactions among particulate ammonium sulfates and nitrates and gas phase nitric acid and ammonia vary with temperature, humidity, and location. Both ambient observations and modeling simulations suggest that regional SO_2 reductions are effective at reducing sulfate and associated ammonium, and, therefore, $PM_{2.5}$. Under certain conditions reductions in particulate ammonium sulfates can release ammonia as a gas, which then reacts with gaseous nitric acid to form nitrate particles, a phenomenon called "nitrate replacement." In such conditions SO_2 reductions would be less effective in reducing $PM_{2.5}$, unless accompanied by reductions in NO_X emissions to address the potential increase in nitrates.

(4) Reductions in ammonia can reduce the ammonium, but not the sulfate portion of sulfate particles. The relative efficacy of reducing nitrates through NO_X or ammonia control varies with atmospheric conditions; the highest particulate nitrate concentrations in the East tend to occur in cooler months and regions. At present, our knowledge about sources, emissions, control approaches, and costs is greater for NO_X than for ammonia. Measures to reduce NO_X from stationary and mobile sources have been implemented for more than 20 years. From a chemical perspective, as NO_X reductions accumulate relative to ammonia, the atmospheric chemical system would move towards an equilibrium in which ammonium nitrate reductions become more responsive to further NO_X reductions relative to ammonia reductions.

(5) Much less is known about the sources of regional transport of carbonaceous material. Key uncertainties include how much of this material is due to biogenic as compared to anthropogenic sources, and how much is directly emitted as compared to formed in the atmosphere.

Based on the understanding of current scientific and technical information, as well as EPA's air quality modeling, as summarized in the CAIR proposal, EPA concluded that it was both appropriate and necessary to focus on control of SO_2 and NO_X emissions as the most effective approach to reducing the contribution of interstate transport to $PM_{2.5}$.

For the CAIR, the EPA did not include emissions controls that affect other components of $PM_{2.5}$, noting that "current information relating to sources and controls for other components identified in transported $PM_{2.5}$ (carbonaceous particles, ammonium, and crustal materials) does not, at this time, provide an adequate basis for regulating the regional transport of emissions responsible for these $PM_{2.5}$ components." (69 FR 4582). For all of these components, the lack of knowledge of and ability to quantify accurately the interstate transport of these components limited EPA's ability to include these components in the CAIR.

b. For the CAIR, how did EPA determine which pollutants were necessary to control to address interstate transport for ozone?

In the notice of proposed rulemaking for the CAIR, EPA provided the following characterization of the origin and distribution of 8-hour ozone air quality problems:

The ozone present at ground level as a principal component of photochemical smog is formed in sunlit conditions through atmospheric reactions of two main classes of precursor compound: VOCs and NO_X (mainly NO and NO_2). The term "VOC" includes many classes of compounds that possess a wide range of chemical properties and atmospheric lifetimes, which help determine their relative importance in forming ozone. Sources of VOCs include man-made sources such as motor vehicles, chemical plants, refineries, and many consumer products, but also natural emissions from vegetation. Nitrogen oxides contributing to ozone formation are emitted by motor vehicles, power plants, and other combustion sources, with lesser amounts from natural processes including lightning and soils. Key aspects of current and projected inventories for NO_X and VOC are summarized in section IV of the proposal notice and EPA Web sites (*e.g., http://www.gov/ttn/chief.*) The relative importance of NO_X and VOC in ozone formation and control varies with local- and time-specific factors, including the relative amounts of VOC and NO_X present. In rural areas with high concentrations of VOC from biogenic sources, ozone formation and control is governed by NO_X. In some urban core situations, NO_X concentrations can be high enough relative to VOC to suppress ozone formation locally, but still contribute to increased ozone downwind from the city. In such situations, VOC reductions are most effective at reducing ozone within the urban environment and immediately downwind. The formation of ozone increases with temperature and sunlight, which is one reason ozone levels are higher during the summer. Increased temperature also increases emissions of volatile man-made and biogenic organics and can indirectly increase NO_X as well (*e.g.*, increased electricity generation for air conditioning). Summertime conditions also bring increased episodes of large-scale stagnation, which promote the build-up of direct emissions and pollutants formed through atmospheric reactions over large regions. Authoritative assessments of ozone control approaches have concluded that, for reducing regional scale ozone transport, a NO_X control strategy would be most effective, whereas VOC reductions are most effective in more dense urbanized areas.

Studies conducted in the 1970s established that ozone occurs on a regional scale (*i.e.*, 1,000s of kilometers) over much of the eastern U.S., with elevated concentrations occurring in rural as well as metropolitan areas. While substantial progress has been made in reducing ozone in many urban areas, regional scale ozone transport is still an important component of high ozone concentrations during the extended summer ozone season. A series of more recent progress reports discussing the effect of the NO_X SIP Call reductions can be found on EPA's Web site at: *http://www.epa.gov/airmarkets/progress/progress-reports.html.*

In the notice of proposed rulemaking for CAIR, EPA noted that we continue to rely on the assessment of ozone transport made in great depth by the OTAG in the mid-1990s. As indicated in the NO_X SIP Call proposal, the OTAG Regional and Urban Scale Modeling and Air Quality Analysis Work Groups concluded that regional NO_X emissions reductions are effective in producing ozone benefits; the more NO_X reduced, the greater the benefit.

More recent assessments of ozone, for example those conducted for the Regulatory Impact Analysis for the ozone standards in 2008, continue to show the importance of NO_X transport. Information on these analyses can be found at EPA's Web site at: *http://www.epa.gov/ttn/ecas/regdata/RIAs/452_R_08_003.pdf*.

For addressing interstate ozone transport in the CAIR, EPA addressed NO_X emissions, but did not include requirements for VOCs. EPA believes that VOCs from some upwind states do indeed have an impact in some nearby downwind states, particularly over short transport distances. The EPA expects that states will need to examine the extent to which VOC emissions affect ozone pollution levels across state lines, and identify areas where multi-state VOC strategies might assist in meeting the 8-hour standard, in planning for attainment.

c. For the CAIR, which thresholds were used to identify states included under the rule?

(1) Fine Particles

In the CAIR, EPA used as the metric for identifying a state as significantly contributing (depending upon further consideration of costs) to downwind nonattainment, the predicted change, due to the upwind state's NO_X and SO_2 emissions, in annual[19] $PM_{2.5}$ concentration in the downwind nonattainment area that receives the largest ambient impact. The EPA proposed this metric in the form of a range of alternatives for a "bright line," that is, air quality impacts at or greater than the chosen threshold level indicated that the upwind state's emissions do contribute significantly (depending on cost considerations), and that air quality impacts below the threshold indicate that the upwind state's emissions do not contribute significantly to nonattainment.

This metric addresses how much each state contributes to a downwind neighbor. EPA does not believe that a particular upwind state must contribute to multiple downwind receptors to be required to make emissions reductions under CAA section 110(a)(2)(D). Under this provision, an upwind state must include in the SIP adequate provisions that prohibit that state's emissions that "contribute significantly to nonattainment in * * * any other State * * *" 42 U.S.C. 7410(a)(2)(D)(i)(I). Our interpretation of this provision is that the emphasized terms make clear that the upwind state's emissions must be controlled as long as they contribute significantly to a single nonattainment area.

As discussed in section II of the preamble to the final CAIR, EPA's approach to evaluating a state's impact on downwind nonattainment considered the entirety of the state's SO_2 and NO_X emissions, rather than treating them separately. We believed this approach was consistent with the chemical interactions in the atmosphere of SO_2 and NO_X in forming $PM_{2.5}$. The contributions of SO_2 and NO_X emissions are generally not additive, but rather are interrelated due to complex chemical reactions.

In the CAIR proposal, EPA proposed to establish a state-level annual average $PM_{2.5}$ contribution threshold from anthropogenic SO_2 and NO_X emissions that was a small percentage of the annual air quality standard of 15.0 μg/m³. The EPA based this proposal on the general concept that an upwind state's contribution of a relatively low level of ambient impact should be regarded as significant (depending on the further assessment of the control costs). We based our reasoning on several factors. The EPA's modeling indicates that at least some nonattainment areas will find it difficult to attain the standards without reductions in upwind emissions. In addition, our analysis of base case $PM_{2.5}$ transport shows that, in general, $PM_{2.5}$ nonattainment problems result from the combined impact of relatively small contributions from many upwind states, along with contributions from in-state sources and, in some cases, substantially larger contributions from a subset of particular upwind states. In the NO_X SIP Call rulemaking, we termed this pattern of contribution—which is also present for ozone nonattainment—"collective contribution."

In the case of $PM_{2.5}$, we have found collective contribution to be a pronounced feature of the $PM_{2.5}$ transport problem, in part because the annual nature of the $PM_{2.5}$ NAAQS means that throughout the entire year and across a range of wind patterns—rather than during just one season of the year or on only the few worst days during the year which may share a prevailing wind direction—emissions from many upwind states affect the downwind nonattainment area.

As a result, to address the transport affecting a given nonattainment or maintenance area, many upwind states must reduce their emissions, even though their individual contributions may be relatively small. As a result, for the CAIR EPA determined that a relatively low value for the $PM_{2.5}$ transport contribution threshold was appropriate. For the final CAIR EPA decided to apply a threshold of 0.20 μg/m³, such that any model result that is below this value (0.19 or less) indicates a lack of significant contribution, while values of 0.20 or higher exceeded the threshold.

(2) Ozone

For the CAIR ozone program, in assessing the contribution of upwind states to downwind 8-hour ozone nonattainment, EPA followed the approach used in the NO_X SIP Call and employed the same contribution metrics, but with an updated model and updated inputs.

The air quality modeling approach we proposed to quantify the impact of upwind emissions included two different methodologies: Zero-out and source apportionment. EPA applied each methodology to estimate the impact of all of the upwind state's anthropogenic NO_X and VOC emissions on each downwind nonattainment area.

The EPA's first step in evaluating the results of these methodologies was to remove from consideration those states whose upwind contributions were very low. Specifically, EPA considered an upwind state not to contribute significantly to a downwind nonattainment area if the state's maximum contribution to the area was either (1) less than 2 ppb; or (2) less than one percent of total nonattainment in the downwind area; as indicated by either of the two modeling techniques.

If the upwind state's impact exceeded these thresholds, then EPA conducted a further evaluation to determine if the impact was high enough to meet the air quality portion of the "contribute significantly" standard. In doing so, EPA organized the outputs of the two modeling techniques into a set of "metrics." The metrics reflect three key contribution factors:

- The magnitude of the contribution (actual amount of ozone contributed by emissions in the upwind state to nonattainment in the downwind area);
- The frequency of the contribution (how often contributions above certain thresholds occur); and
- The relative amount of the contribution (the total ozone

[19] For the CAIR, 24-hour $PM_{2.5}$ was not at issue because there were little or no exceedances of the then-existing 65 μg/m³ 24-hour standards

contributed by the upwind state compared to the total amount of nonattainment ozone in the downwind area).

2. Approach for Proposed Rule

a. Which pollutants do we propose to control?

For the proposed rule, EPA believes that the conclusions and findings in the final CAIR regarding the nature of pollutant contributions are still appropriate. EPA proposes to continue to focus the $PM_{2.5}$ transport requirements on SO_2 and NO_X transport, and the ozone transport requirements on NO_X.

EPA recognizes that, in some circumstances, the state's NO_X contribution to $PM_{2.5}$ in downwind states may be considerably smaller than the state's SO_2 contribution to $PM_{2.5}$ in downwind states. In addition, for monitors in EPA's speciation trends network that are located in southern states with warmer climates, the level of monitored nitrates can be very small. For these states, it is possible that annual NO_X controls, within levels that could realistically be achieved, would result in a very small change in ambient $PM_{2.5}$ levels. EPA considered identifying states where this was the case. For a number of reasons, we propose not to take this course of action. First, these states can impact downwind states in cooler climates, and thus impact nitrate formation in those downwind states. For example, EPA modeling results show that Georgia's emissions are linked to Ohio, Maryland, New Jersey, and Pennsylvania where monitored nitrates are higher. Second, EPA is concerned with the possibility for the "nitrate replacement" effect described previously. That is, there is a possibility for increases in nitrate particles if SO_2 emissions decrease without accompanying decreases in NO_X. Third, EPA believes that there would be important disbenefits to relaxing annual NO_X requirements in those states. If for those states, EPA were to relax the annual NO_X requirements currently required for their contribution to $PM_{2.5}$, annual NO_X emissions would increase, with potentially harmful effects on visibility and nitrogen deposition.

b. Thresholds

For the proposed rule, as for CAIR, EPA uses air quality thresholds to identify states whose contributions do not warrant transport requirements. We propose air quality thresholds for annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and 8-hour ozone. Each threshold is based on 1 percent of the NAAQS.

As we found at the time of the CAIR, EPA's analysis of base case $PM_{2.5}$ transport shows that, in general, $PM_{2.5}$ nonattainment problems result from the combined impact of relatively small contributions from many upwind states, along with contributions from in-state sources and, in some cases, substantially larger contributions from a subset of particular upwind states. For ozone, as we found in the CAIR and the SIP call, we also found important contributions from multiple upwind states. In short, EPA continues to find an upwind "collective contribution" that is important to both $PM_{2.5}$ and ozone.

A second reason that low threshold values are warranted, as EPA discussed in the notices for the CAIR, is that there are adverse health impacts associated with ambient $PM_{2.5}$ and ozone even at low levels. See relevant portions of the CAIR proposal notice (63 FR 4583–84) and the CAIR final rule notice (70 FR 25189–25192).

For annual $PM_{2.5}$ for the final CAIR, as noted previously, EPA decided to use a single-digit value, 0.2 μg/m³, rather than the two-digit value in the proposed CAIR, 0.15 μg/m³. The rationale for the single digit value for the final rule was that a single digit is consistent with the EPA monitoring requirements in part 50, appendix N, section 4.3. The reporting requirements for annual $PM_{2.5}$ require that:

> Annual $PM_{2.5}$ standard design values shall be rounded to the nearest 0.1 μg/m³ (decimals 0.05 and greater are rounded up to the next 0.1, and any decimal lower than 0.05 is rounded down to the nearest 0.1).

Because the design value is to be reported only to the nearest 0.1 μg/m³, EPA deemed it preferable for the final CAIR to select the threshold value at the nearest 0.1 μg/m³ as well, and hence one percent of the 15 μg/m³, rounded to the nearest 0.1 μg/m³ became 0.2 μg/m³.

For the 24-hour standard of 35 μg/m³, we attempted to apply the same rationale for determining a single-digit air quality threshold. That is, we applied rounding conventions in Part 50, Appendix N to a value representing one percent of the NAAQS. The rounding requirements for the 24-hour standard are indicated in section 4.3 as follows:

> 24-hour $PM_{2.5}$ standard design values shall be rounded to the nearest 1 μg/m³ (decimals 0.5 and greater are rounded up to the nearest whole number, and any decimal lower than 0.5 is rounded down to the nearest whole number).

One percent of the 24-hour standard is 0.35 μg/m³, and rounding to the nearest whole μg/m³ would yield an air quality threshold of zero. Thus applying the same rationale for the final CAIR, there would be no air quality threshold for 24-hour $PM_{2.5}$, which EPA believes to be counterintuitive and unworkable as an approach for assessing interstate contributions.

For the proposed rule, EPA proposes to decouple the precision of the air quality thresholds with the monitoring reporting requirements, and to use 2-digit values representing one percent of the NAAQS, that is, 0.15 μg/m³ for the annual standard, and 0.35 μg/m³ for the 24-hour standard. EPA believes there are a number of considerations favoring this approach. First, it provides for a consistent approach for the annual and 24-hour standards. Second, the approach is readily applicable to any current and future NAAQS. For example, if EPA were to retain the CAIR approach for the annual standard, any future lowering of the $PM_{2.5}$ NAAQS to below 15 μg/m³ would reduce the air quality threshold to 0.1 μg/m³. This would occur because any value less than 0.15 μg/m³ (*e.g.*, 0.14 μg/m³) would be rounded down to 0.1 μg/m³. EPA finds it within its discretion to adjust its approach to account for the additional considerations that were not in existence at the time of the final CAIR.

For the proposal, EPA is proposing to take a more straightforward approach to air quality thresholds for ozone than the multi-factor approach we used for the NO_X SIP Call or for the CAIR. The proposed approach uses a single "bright line" threshold for ozone that is one percent of the 1997 8-hour ozone standard of 0.08 ppm. As described later in section IV.C, the 1 percent threshold is averaged over multiple model days. EPA believes this to be a robust metric compared to previous metrics which might have relied on the maximum contribution on a single day. Under this approach, one percent of the NAAQS is a value of 0.8 ppb. State contributions of 0.8 ppb and higher are above the threshold; ozone contributions less than 0.8 ppb are below the threshold. EPA believes that this approach is preferable because it is a robust metric, it is consistent with the approach for $PM_{2.5}$, and because it provides for a consistent approach that takes into account, and is applicable to, any future ozone standards below 0.08 ppm.

EPA seeks comment on the pollutants and air quality thresholds used for identifying states to be included under the proposed rule. In particular, EPA requests comment on alternatives to the 1 percent threshold. In addition, EPA requests comment on whether EPA should use the same rounding convention that was used in the final CAIR for the 15 µg/m³ annual $PM_{2.5}$ standard, or whether commenters agree with EPA's approach that does not use this rounding convention. To identify the potential effect of alternative thresholds for the annual $PM_{2.5}$ standard, *see* Table IV.C–13 (showing state specific contributions to areas with annual $PM_{2.5}$ nonattainment and maintenance issues) and Table IV.C–16 (showing state specific contributions to areas with 24-hour $PM_{2.5}$ nonattainment and maintenance issues).

C. Air Quality Modeling Approach and Results

1. What air quality modeling platform did EPA use?

a. Introduction

In this section, we describe the air quality modeling performed to support the proposed rule. We used air quality modeling to (1) identify locations where we expect there to be nonattainment or maintenance problems for annual average $PM_{2.5}$, 24-hour $PM_{2.5}$, and/or 8-hour ozone for the analytic years chosen for this proposal, (2) quantify the impacts (*i.e.*, air quality contributions) of SO_2 and NO_X emissions from upwind states on downwind annual average and 24-hour $PM_{2.5}$ concentrations at monitoring sites projected to be nonattainment or have maintenance problems in 2012 for the 1997 annual and 2006 24-hour $PM_{2.5}$ NAAQS, respectively, (3) quantify the impacts of NO_X emissions from upwind states on downwind 8-hour ozone concentrations at monitoring sites projected to be nonattainment or have maintenance problems in 2012 for the 1997 ozone NAAQS, and (4) assess the health and welfare benefits of the emissions reductions expected to result from this proposal. This section includes information on the air quality model applied in support of the proposed rule, the meteorological and emissions inputs to these models, the evaluation of the air quality model compared to measured concentrations, and the procedures for projecting ozone and $PM_{2.5}$ concentrations for future year scenarios. We also provide in this section the interstate contributions for annual average and 24-hour $PM_{2.5}$, and 8-hour ozone. The Air Quality Modeling Technical Support Document (AQMTSD) contains more detailed information on the air quality modeling aspects of this rule.

To support the proposal, air quality modeling was performed for four emissions scenarios: A 2005 base year, a 2012 "no CAIR" base case, a 2014 "no CAIR" base case, and a 2014 control case that reflects the emissions reductions expected from the proposed FIPs. The remedy proposed for inclusion in the FIPs is described in section V.D. The modeling for 2005 was used as the base year for projecting air quality for each of the 3 future year scenarios. The 2012 base case modeling was used to identify future nonattainment and maintenance locations and to quantify the contributions of emissions in upwind states to annual average and 24-hour $PM_{2.5}$ and 8-hour ozone. The 2014 base case and 2014 control case modeling were used to quantify the benefits of this proposal.

For CAIR, EPA used the Comprehensive Air Quality Model with Extensions (CAMx) version 5 [20] to simulate ozone and $PM_{2.5}$ concentrations for the 2005 base year and the 2012 and 2014 future year scenarios. In contrast, for the CAIR EPA used two air quality models, CAMx version 3.1 for modeling ozone and the Community Multiscale Air Quality Model (CMAQ) version 4.3 for modeling $PM_{2.5}$. Both CAMx and CMAQ are grid cell-based, multi-pollutant photochemical models that simulate the formation and fate of ozone and fine particles in the atmosphere. The use of one model for both pollutants, as we have done for this proposal, provides a more scientifically integrated "one atmosphere" approach versus using different models for ozone and $PM_{2.5}$. In addition, using a single model rather than two models is computationally more efficient. The CAMx model applications were designed to cover states in the central and eastern U.S. using a horizontal resolution of 12 x 12 km.[21] The modeling region (*i.e.*, modeling domain) extends from Texas northward to North Dakota and eastward to the East Coast and includes 37 states and the District of Columbia. A map of the air quality modeling domain is provided in the AQMTSD.

Both CAMx and CMAQ contain certain source apportionment tools that are designed to quantify the contribution of emissions from various sources and areas to ozone and $PM_{2.5}$ component species in other downwind locations. The CAMx model was chosen for use in this proposal because the source apportionment tools in this model have had extensive use and evaluation by states and industry. Also, the source apportionment tools in CAMx received favorable comments in a recent peer review.[22]

The 2005-based air quality modeling platform used for the proposal includes 2005 base year emissions and 2005 meteorology for modeling ozone and $PM_{2.5}$ with CAMx. This platform provides an update to the now more historical data in the 2001-based platform used for CAIR that included 2001 emissions, 2001 meteorology for modeling $PM_{2.5}$, and 1995 meteorology for modeling ozone. In the remainder of this section we provide an overview of (1) the emissions and meteorological components of the 2005-based platform, (2) the methods for projecting future nonattainment and maintenance along with a list of 2012 base case nonattainment and maintenance locations, (3) the approach to developing metrics to measure interstate contributions to annual and 24-hour $PM_{2.5}$ and ozone, and (4) the predicted interstate contributions to downwind nonattainment and maintenance. We also identify which predicted interstate contributions are at or above the air quality impact thresholds described previously in section IV.B.

b. Emissions Inventories

Emissions estimates were made for a 2005 base year and for 2012 and 2014. All inventories include emissions from EGUs, nonEGU point sources, stationary nonpoint sources, onroad mobile sources, and nonroad mobile sources. When emissions were only available at annual or monthly temporal resolutions, emissions modeling steps were applied to estimate hourly emissions. Point source emissions were assigned to modeling grid cells based on latitude and longitude in the inventory, and county total emissions were allocated to grid cells. Emissions of NO_X, VOCs and $PM_{2.5}$ were split into their component species using other data sources, to provide the modeling species needed by CAMx. Elevated point sources were identified for simulating releases of emissions from those sources in layers 2 and higher in CAMx. In addition to the anthropogenic emission sources described previously, hourly, gridded biogenic emissions were estimated for individual modeling days using the BEIS model version 3.14.[23] [24] The same

[20] Comprehensive Air Quality Model with Extensions Version 5 User's Guide. Environ International Corporation. Novato, CA. March 2009.

[21] The 12 km domain was nested within a coarse grid, 36 x 36 km modeling domain which covers the lower 48 states and adjacent portions of Canada and Mexico. Predictions from this Continental U.S. (CONUS) domain were used to provide initial and boundary concentrations for simulations in the 12 km domain.

[22] Arunachalam, S. Peer Review of Source Apportionment Tools in CAMx and CMAQ, EP–D–07–102. University of North Carolina, Institute for the Environment, August 2009.

[23] Pouliot, G., Pierce., T. "A Tale of Two Models: A comparison of the Biogenic Emission Inventory System (BEIS) and Model of Emissions of Gases and

biogenic emissions data were used in all scenarios modeled.

(1) Development of 2005 Base Year Emissions

Emissions inventory inputs representing the year 2005 were developed to provide a base year for forecasting future air quality, described in section IV.C.2. The 2005 National Emission Inventory (NEI), version 2 from October 6, 2008, was the starting point for the U.S. inventories used for the 2005 air quality modeling. This inventory includes 2005-specific data for point and mobile sources, while most nonpoint data were carried forward from version 3 of the 2002 NEI. In addition, a 2006 Canadian inventory and a 1999 Mexican inventory were used for the portions of Canada and Mexico within the modeling domains. Additional details on these inventories and the augmentation described here are available from the Emissions Inventory Technical Support Document (EITSD) for the Transport Rule.

The onroad and nonroad emissions were primarily based on the National Mobile Inventory Model (NMIM) monthly, county, process level emissions from the 2005 NEI v2. The 2005 onroad mobile emissions were augmented for onroad gasoline emissions sources with emissions based on a draft version of the Motor Vehicle Emissions Simulator (MOVES) for carbon monoxide (CO), NO_X, VOC, $PM_{2.5}$, and particulate matter less than ten microns (PM_{10}). While these data were preliminary, they more closely reflect the $PM_{2.5}$ emissions from the final release of MOVES 2010. To account for the temperature dependence of $PM_{2.5}$, MOVES-based temperature adjustment factors were applied to gridded, hourly emissions using gridded, hourly meteorology. Additional information on this approach is available in the EITSD.

The annual NO_X and SO_2 emissions for EGUs in the 2005 NEI v2 are based primarily on data from EPA's Clean Air Markets Division's Continuous Emissions Monitoring (CEM) program, with other pollutants estimated using emission factors and the CEM annual heat input. For EGUs without CEMs, data were obtained from the states as included in the NEI. For modeling, the 2005 EGU emissions for SO_2 and NO_X were augmented by using hourly CEM data to develop a temporal allocation approach of the 2005 NEI v2 emissions. The annual emissions themselves were unchanged, and match closely with data from the CEM program except where states have provided data for partial CEM and non-CEM units. The 2005 EGUs were identified as all units in 2005 that map to the units modeled by the version of the Integrated Planning Model (IPM) used for this proposal, and include records both with and without data submitted to the CEM program. Temporal profiles were used instead of the actual 2005 CEM data so that the temporal allocation approach could be consistent in the future year modeling.

For the 2005 base year, the annual EGU NEI emissions were allocated to hourly emissions values needed for modeling based on the 2004, 2005, and 2006 CEM data. The NO_X CEM data were used to create NO_X-specific profiles, the SO_2 data were used to create SO_2-specific profiles, and the heat input data were used to allocate all other pollutants. The 3 years of data were used to create state-specific profiles to allocate from annual to monthly values and from daily to hourly values. Only the 2005 data were used to create state-specific factors for allocation from month to day, which is intended to preserve an appropriate level of daily temporal variability needed for this type of modeling.

Other significant augmentations were also made to the 2005 NEI and include the following. The nonpoint inventory was augmented with the oil and gas exploration inventory [25] which includes emissions in several states within the eastern U.S. 12 km modeling domain and additional states within the national 36 km modeling domain. The commercial marine category 3 (C3) vessel emissions were augmented with gridded 2005 emissions from the previous modeling efforts for the rule called "Control of Emissions from New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder." The 2005 point source daily wildfire and prescribed burning emissions were replaced with average-year county-based inventories. Additionally, the inventories were processed to provide the hourly, gridded, model-species needed by CAMx.

Tables IV.C–1 and IV.C–2 provide summaries of SO_2 and NO_X emissions by state by sector for the 2005 base year for those states within the eastern 12 km modeling domain. Emissions for other states within the 36 km modeling domain are available in the EISTD. In the tables, the EGU column summarizes all units matched to the IPM model and the nonEGU column is for other point source units. The Nonpoint column shows emissions for all nonpoint stationary sources. The Nonroad column summarizes emissions for nonroad mobile sources, including aircraft, locomotive, and marine sources including the C3 commercial marine. The Onroad column summarizes emissions for the combined NEI and draft MOVES-based emissions, in which emissions from the draft MOVES were used when available, and NEI emissions based on MOBILE6 were used for the remainder. Finally, the Fires column represents the average-year fire emissions for wildfires and prescribed burning mentioned previously.

TABLE IV.C–1—2005 BASE CASE SO_2 EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Alabama	460,123	70,346	52,325	6,397	3,199	983	593,372
Arkansas	66,384	13,066	27,260	5,678	1,632	728	114,749
Connecticut	10,356	1,831	18,455	2,548	1,128	4	34,320
Delaware	32,378	34,859	5,859	11,648	422	6	85,173
District of Columbia	1,082	686	1,559	414	172	0	3,914
Florida	417,321	57,475	70,490	93,543	10,285	7,018	656,131
Georgia	616,054	56,116	56,829	13,331	5,690	2,010	750,031
Illinois	330,382	156,154	5,395	19,302	5,716	20	516,969
Indiana	878,978	95,200	59,775	9,436	3,981	24	1,047,396
Iowa	130,264	61,241	19,832	8,838	1,702	25	221,902
Kansas	136,520	13,142	36,381	8,035	1,824	103	196,005

Aerosols from Nature (MEGAN)," 7th Annual Community Multiscale Analysis System Conference, Chapel Hill, NC, October 6–8, 2008.

[24] Donna Schwede, D., Pouliot, G., and Pierce, T. "Changes to the Biogenic Emissions Inventory System Version 3 (BEIS3)," 4th Annual Community Multiscale Analysis System Conference, Chapel Hill, NC, September 26–28, 2005.

[25] The oil and gas exploration inventory was provided by the Western Regional Air Partnership.

TABLE IV.C–1—2005 BASE CASE SO_2 EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR—Continued

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Kentucky	502,731	25,811	34,229	6,942	2,711	364	572,787
Louisiana	109,851	165,737	2,378	73,233	2,399	892	354,489
Maine	3,887	18,519	9,969	3,725	834	150	37,084
Maryland	283,205	34,988	40,864	17,819	2,966	32	379,874
Massachusetts	85,768	19,620	25,261	25,335	2,168	93	158,245
Michigan	349,877	76,510	42,066	14,533	7,204	91	490,280
Minnesota	101,666	25,169	14,747	10,410	2,558	631	155,181
Mississippi	74,117	29,892	6,796	6,003	2,158	1,051	120,016
Missouri	284,384	78,307	44,573	10,464	4,251	186	422,165
Nebraska	74,955	6,429	29,575	9,199	1,326	105	121,589
New Hampshire	51,445	3,245	7,408	805	630	38	63,571
New Jersey	57,044	7,640	10,726	23,484	2,486	61	101,441
New York	180,847	58,562	125,158	20,908	5,628	113	391,216
North Carolina	512,231	66,150	22,020	42,743	5,341	696	649,181
North Dakota	137,371	9,458	6,455	5,986	443	66	159,779
Ohio	1,116,084	118,468	19,810	15,615	6,293	22	1,276,292
Oklahoma	110,081	40,482	7,542	5,015	2,699	469	166,288
Pennsylvania	1,002,202	85,411	68,349	11,972	5,363	32	1,173,328
Rhode Island	176	2,743	3,365	2,494	208	1	8,987
South Carolina	218,782	31,495	30,016	20,477	2,976	646	304,393
South Dakota	12,215	1,698	10,347	3,412	511	498	28,682
Tennessee	266,148	78,206	32,714	6,288	4,834	277	388,468
Texas	534,949	223,625	109,215	52,749	13,470	1,178	935,187
Vermont	9	902	5,385	385	305	49	7,036
Virginia	220,248	69,440	32,923	18,420	3,829	399	345,259
West Virginia	469,456	48,314	14,589	2,133	1,095	215	535,802
Wisconsin	180,200	66,807	6,369	7,129	3,110	70	263,685
Grand total	10,019,774	1,953,745	1,117,009	596,847	123,547	19,345	13,380,267

TABLE IV.C–2—2005 BASE CASE NO_X EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Alabama	133,051	74,830	32,024	61,623	142,221	3,814	447,562
Arkansas	35,407	37,478	21,453	63,493	81,014	2,654	241,499
Connecticut	6,865	5,824	12,554	21,785	69,645	14	116,688
Delaware	11,917	5,567	3,259	15,567	22,569	23	58,902
District of Columbia	492	501	1,740	3,494	9,677	0	15,904
Florida	217,263	53,778	29,533	277,888	460,474	25,600	1,064,537
Georgia	111,017	53,297	38,919	95,175	279,449	7,955	585,812
Illinois	127,923	97,504	47,645	223,697	276,507	71	773,347
Indiana	213,503	73,647	30,185	110,100	187,426	88	614,949
Iowa	72,806	39,299	15,150	92,965	91,795	90	312,105
Kansas	90,220	70,785	42,286	86,553	76,062	378	366,285
Kentucky	164,743	35,432	17,557	90,669	127,435	1,326	437,163
Louisiana	63,791	165,162	27,559	301,170	112,889	3,254	673,824
Maine	1,100	18,309	7,423	13,379	38,469	566	79,246
Maryland	62,574	24,621	21,715	55,812	129,796	137	294,656
Massachusetts	25,618	18,429	34,373	74,419	118,148	341	271,327
Michigan	120,005	94,139	43,499	101,087	279,816	330	638,876
Minnesota	83,836	64,438	56,700	115,873	146,138	2,300	469,286
Mississippi	45,166	53,985	12,212	79,394	98,060	3,833	292,649
Missouri	127,431	38,604	32,910	123,228	183,022	678	505,873
Nebraska	52,426	12,156	13,820	107,180	58,643	381	244,607
New Hampshire	8,827	3,241	11,235	9,246	32,537	137	65,223
New Jersey	30,114	20,598	26,393	88,486	157,736	223	323,550
New York	63,465	55,122	87,608	121,363	282,072	412	610,042
North Carolina	111,576	44,502	18,869	135,936	225,756	11,424	548,064
North Dakota	76,381	7,545	10,046	59,635	21,575	240	175,422
Ohio	258,687	71,715	41,466	173,988	270,383	81	816,321
Oklahoma	86,204	73,465	94,574	55,424	117,240	1,709	....
Pennsylvania	176,870	89,208	53,435	118,774	266,649	117	705,053
Rhode Island	545	2,164	2,964	7,798	13,456	4	26,930
South Carolina	53,823	29,069	20,281	68,146	128,765	2,357	302,441
South Dakota	15,650	5,035	5,766	30,324	24,850	1,817	83,442
Tennessee	102,934	60,353	18,676	82,331	207,410	1,012	472,717
Texas	176,170	292,806	274,338	377,246	615,715	4,890	1,741,166
Vermont	297	799	3,438	3,951	13,316	179	21,980
Virginia	62,512	60,101	53,605	91,298	194,173	1,456	463,145
West Virginia	159,804	36,913	14,519	32,739	50,040	785	294,801

TABLE IV.C–2—2005 BASE CASE NO_X EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR—Continued

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Wisconsin	72,170	40,688	21,994	75,981	147,952	256	359,042
Grand total	3,223,184	1,931,111	1,301,726	3,647,215	5,758,880	80,931	15,943,047

(2) Development of Future Year Emissions

The future base case scenarios represent predicted emissions in the absence of any further controls beyond those federal measures already promulgated. For EGUs, all state and other programs available at the time of modeling have been included. For mobile sources, all national measures available at the time of modeling have been included. For nonEGU point and nonpoint stationary sources, any local control programs that may be necessary for areas to attain the annual $PM_{2.5}$ NAAQS and the ozone NAAQS are not included in the future base case projections. The future base case scenarios do reflect projected economic changes and fuel usage for EGU and mobile sectors, as described in the EITSD.

Tables IV.C–3 through IV.C–6 provide 2012 and 2014 summaries of emissions data for 2012 and 2014 modeling for all sectors for SO_2 and NO_X for states included in the 12 km modeling domain. The EITSD provides summaries for additional pollutants with additional detail and for all states in the nationwide 36 km modeling domain.

TABLE IV.C–3—2012 BASE CASE SO_2 EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Alabama	335,734	70,346	52,315	2,333	585	983	462,297
Arkansas	85,068	13,054	27,257	818	336	728	127,259
Connecticut	5,493	1,831	18,443	1,292	330	4	27,392
Delaware	7,841	10,974	5,858	14,193	98	6	38,970
District of Columbia	0	686	1,559	10	41	0	2,296
Florida	228,360	57,491	70,482	102,076	2,072	7,018	467,498
Georgia	552,007	56,122	56,817	7,984	1,253	2,010	676,193
Illinois	724,657	133,201	5,384	1,960	1,174	20	866,396
Indiana	829,988	95,201	59,767	871	775	24	986,626
Iowa	169,039	61,242	19,821	482	346	25	250,954
Kansas	59,567	13,048	36,376	518	302	103	109,915
Kentucky	718,980	25,813	34,214	1,368	510	364	781,249
Louisiana	100,239	159,722	2,373	78,051	455	892	341,731
Maine	15,759	18,519	9,950	3,926	156	150	48,460
Maryland	49,078	34,988	40,854	17,112	608	32	142,672
Massachusetts	16,299	19,622	25,242	29,825	575	93	91,657
Michigan	287,807	76,458	42,066	7,636	1,074	91	415,132
Minnesota	53,596	25,100	14,733	1,342	596	631	95,997
Mississippi	46,432	24,426	6,788	2,094	375	1,051	81,166
Missouri	445,643	78,310	44,550	1,307	765	186	570,761
Nebraska	120,790	6,430	29,571	817	209	105	157,921
New Hampshire	7,290	3,245	7,396	72	142	38	18,183
New Jersey	37,746	6,747	10,715	25,286	772	61	81,327
New York	144,074	58,566	125,187	12,336	1,541	113	341,818
North Carolina	126,620	66,128	22,000	48,861	935	696	265,240
North Dakota	77,383	9,458	6,451	288	76	66	93,722
Ohio	946,667	105,406	19,810	3,456	1,131	22	1,076,493
Oklahoma	156,032	36,912	7,536	341	502	469	201,791
Pennsylvania	966,136	79,142	68,330	4,938	1,135	32	1,119,712
Rhode Island	0	2,743	3,364	2,879	82	1	9,069
South Carolina	149,515	31,452	30,005	22,697	532	646	234,846
South Dakota	13,453	1,698	10,342	65	91	498	26,147
Tennessee	596,987	77,595	32,701	828	795	277	709,182
Texas	327,873	162,915	109,199	37,109	2,409	1,178	640,682
Vermont	0	902	5,381	6	94	49	6,432
Virginia	145,452	69,166	32,904	15,158	883	399	263,963
West Virginia	588,392	41,817	14,583	443	197	215	645,646
Wisconsin	107,365	66,452	6,370	928	646	70	181,830
Grand total	9,243,362	1,802,927	1,116,694	451,705	24,595	19,345	12,658,628

TABLE IV.C–4—2012 BASE CASE NO_X EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Alabama	121,809	74,832	31,958	49,622	82,135	3,814	364,171
Arkansas	43,222	37,479	21,429	48,349	46,959	2,654	200,092
Connecticut	2,770	5,830	12,475	15,865	37,847	14	74,801

TABLE IV.C–4—2012 BASE CASE NO_X EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR—Continued

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Delaware	4,639	5,567	3,248	15,511	10,700	23	39,687
District of Columbia	2	501	1,739	2,704	4,857	0	9,802
Florida	195,673	55,017	29,475	282,147	275,603	25,600	863,515
Georgia	78,011	53,317	38,825	76,901	158,771	7,955	413,780
Illinois	77,920	92,440	47,564	167,046	157,915	71	542,957
Indiana	203,107	73,651	30,125	83,760	114,396	88	505,127
Iowa	66,316	39,301	15,064	72,031	58,920	90	251,721
Kansas	70,823	70,751	42,249	66,897	43,914	378	295,012
Kentucky	149,179	34,875	17,446	72,289	71,284	1,326	346,399
Louisiana	44,773	161,724	27,525	285,562	64,074	3,254	586,912
Maine	3,139	18,309	7,295	13,354	21,896	566	64,559
Maryland	17,376	24,624	21,647	53,580	64,368	137	181,731
Massachusetts	6,312	18,447	34,245	75,149	57,417	341	191,911
Michigan	96,874	93,953	43,392	80,900	163,505	330	478,955
Minnesota	51,285	64,250	56,581	92,080	86,198	2,300	352,694
Mississippi	37,517	52,454	12,151	64,138	52,709	3,833	222,801
Missouri	77,571	38,610	32,731	96,197	108,298	678	354,085
Nebraska	52,820	12,159	13,788	81,177	33,907	381	194,233
New Hampshire	2,514	3,243	11,153	7,308	19,710	137	44,067
New Jersey	15,987	18,996	26,320	81,906	76,979	223	220,410
New York	25,755	55,167	87,776	100,212	154,260	412	423,582
North Carolina	61,643	44,514	18,715	133,476	126,081	11,424	395,854
North Dakota	59,547	7,544	10,018	46,649	12,111	240	136,110
Ohio	159,627	69,075	41,378	133,650	149,134	81	552,945
Oklahoma	86,858	71,808	94,528	43,057	71,207	1,709	369,167
Pennsylvania	193,032	85,168	53,289	92,594	142,217	117	566,418
Rhode Island	221	2,168	2,959	7,468	8,120	4	20,940
South Carolina	47,762	28,953	20,273	63,564	75,994	2,357	238,903
South Dakota	15,493	5,035	5,733	24,117	14,957	1,817	67,151
Tennessee	68,425	59,594	18,573	65,209	126,353	1,012	339,166
Texas	159,738	287,831	274,203	313,204	303,453	4,890	1,343,319
Vermont	0	800	3,406	3,077	10,328	179	17,790
Virginia	36,036	60,101	53,496	79,717	111,583	1,456	342,389
West Virginia	102,725	35,698	14,473	26,040	27,694	785	207,415
Wisconsin	49,351	40,694	21,979	58,951	86,315	256	257,546
Grand Total	2,485,856	1,904,481	1,299,224	3,075,459	3,232,168	80,932	12,078,120

TABLE IV.C–5—2014 BASE CASE SO_2 EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Alabama	322,130	69,150	52,313	1,873	605	983	447,053
Arkansas	88,187	13,055	27,256	142	347	728	129,714
Connecticut	5,512	1,834	18,440	1,294	340	4	27,423
Delaware	7,806	10,974	5,857	14,891	101	6	39,635
District of Columbia	0	686	1,559	4	42	0	2,291
Florida	192,903	57,521	70,480	108,579	2,159	7,018	438,658
Georgia	173,210	56,014	56,813	8,263	1,307	2,010	297,618
Illinois	200,475	133,109	5,381	390	1,221	20	340,596
Indiana	804,294	95,037	59,764	193	810	24	960,123
Iowa	163,966	60,195	19,817	85	360	25	244,448
Kansas	65,125	13,048	36,375	54	313	103	115,018
Kentucky	739,592	23,804	34,210	258	528	364	798,755
Louisiana	94,824	151,216	2,372	78,097	470	892	327,871
Maine	11,650	18,520	9,945	4,215	160	150	44,640
Maryland	42,635	34,994	40,851	16,966	631	32	136,109
Massachusetts	16,299	19,624	25,237	32,043	594	93	93,890
Michigan	275,637	76,437	42,066	7,536	1,107	91	402,874
Minnesota	61,447	25,112	14,728	468	618	631	103,005
Mississippi	48,149	24,427	6,785	1,280	385	1,051	82,077
Missouri	500,649	77,086	44,543	214	796	186	623,473
Nebraska	115,695	6,431	29,570	55	217	105	152,072
New Hampshire	6,608	3,246	7,393	45	148	38	17,476
New Jersey	37,669	6,756	10,712	26,589	799	61	82,585
New York	141,354	58,584	125,196	10,853	1,594	113	337,694
North Carolina	140,585	66,046	21,994	52,897	961	696	283,180
North Dakota	80,320	9,458	5,763	35	78	66	95,720
Ohio	841,194	105,123	19,810	2,085	1,171	22	969,405
Oklahoma	165,773	36,924	7,534	45	524	469	211,268
Pennsylvania	972,977	76,256	68,324	4,117	1,169	32	1,122,876

TABLE IV.C–5—2014 BASE CASE SO_2 EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR—Continued

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Rhode Island	0	2,745	3,364	3,128	85	1	9,323
South Carolina	156,096	31,453	30,002	24,380	551	646	243,129
South Dakota	13,459	1,699	10,298	22	94	498	26,070
Tennessee	600,066	77,605	32,696	173	829	277	711,647
Texas	373,950	155,720	109,194	36,109	2,511	1,178	678,662
Vermont	0	903	5,380	7	101	49	6,439
Virginia	135,741	69,177	32,899	15,624	918	399	254,758
West Virginia	496,307	41,817	14,581	96	201	215	553,218
Wisconsin	117,253	66,456	6,370	638	675	70	191,461
Grand Total	8,209,536	1,778,244	1,116,600	453,742	25,516	19,345	11,602,982

TABLE IV.C–6—2014 BASE CASE NO_X EMISSIONS (TONS/YEAR) FOR EASTERN STATES BY SECTOR

State	EGU	NonEGU	Nonpoint	Nonroad	Onroad	Fires	Total
Alabama	118,420	74,622	31,939	45,932	67,011	3,814	341,738
Arkansas	44,792	37,491	21,422	44,299	38,965	2,654	189,623
Connecticut	2,821	5,854	12,451	14,410	31,534	14	67,084
Delaware	4,513	5,567	3,245	15,270	8,736	23	37,353
District of Columbia	1	501	1,738	2,398	3,929	0	8,568
Florida	180,801	55,343	29,457	278,920	225,478	25,600	795,599
Georgia	48,091	53,557	38,797	71,011	130,240	7,955	349,650
Illinois	80,228	93,059	47,540	151,373	131,403	71	503,676
Indiana	200,899	73,523	30,107	76,024	94,217	88	474,858
Iowa	68,146	38,831	15,038	65,751	48,836	90	236,692
Kansas	78,920	70,730	42,238	61,613	35,950	378	289,829
Kentucky	148,509	34,979	17,413	65,805	57,759	1,326	325,791
Louisiana	45,457	161,766	27,515	274,697	52,360	3,254	565,049
Maine	2,535	18,316	7,257	13,169	18,061	566	59,903
Maryland	19,990	24,687	21,626	52,501	53,040	137	171,980
Massachusetts	6,619	18,527	34,207	75,654	46,748	341	182,095
Michigan	97,455	94,079	43,360	73,939	135,806	330	444,969
Minnesota	51,859	64,372	56,545	84,040	71,161	2,300	330,278
Mississippi	37,142	52,440	12,133	58,559	42,525	3,833	206,633
Missouri	82,979	38,744	32,677	88,233	90,001	678	333,312
Nebraska	52,970	12,173	13,779	75,252	27,856	381	182,410
New Hampshire	2,515	3,255	11,129	6,587	16,260	137	39,884
New Jersey	16,268	19,089	26,298	78,875	63,254	223	204,007
New York	28,350	55,359	87,826	92,841	129,376	412	394,165
North Carolina	61,747	44,573	18,669	133,455	104,150	11,424	374,018
North Dakota	59,556	7,549	3,969	42,972	9,925	240	130,252
Ohio	164,945	69,157	41,352	120,900	122,426	81	518,861
Oklahoma	81,122	72,525	94,513	39,539	58,382	1,709	347,790
Pennsylvania	196,151	84,111	53,246	83,885	118,122	117	535,631
Rhode Island	281	2,186	2,957	7,384	6,772	4	19,585
South Carolina	47,512	28,969	20,271	62,400	62,996	2,357	224,505
South Dakota	15,514	5,039	5,157	22,021	12,254	1,817	62,368
Tennessee	68,779	59,694	18,542	59,145	104,711	1,012	311,882
Texas	166,177	282,509	274,163	289,605	241,009	4,890	1,258,354
Vermont	0	803	3,397	2,771	8,563	179	15,713
Virginia	32,115	60,216	53,464	75,461	92,291	1,456	315,002
West Virginia	100,103	35,700	14,459	23,798	22,863	785	197,708
Wisconsin	53,774	40,729	21,974	53,848	71,163	256	241,743
Grand total	2,468,057	1,900,624	1,298,473	2,884,338	2,656,134	80,932	11,288,558

Development of Future-Year Emissions Inventories for Electric Generating Units

Future year 2012 and 2014 base case EGU emissions used for the air quality modeling runs that predicted ozone and $PM_{2.5}$ were obtained from version 3.02 EISA of the IPM (*http://www.epa.gov/airmarkt/progsregs/epa-ipm/index.html*). The IPM is a multiregional, dynamic, deterministic linear programming model of the U.S. electric power sector; version 3.02 EISA features an updated Title IV SO_2 allowance bank assumption, reflects state rules and consent decrees through February 3, 2009, and incorporates updates related to the Energy Independence and Security Act of 2007. Units with advanced controls (*e.g.*, scrubber, SCR) that were not required to run for compliance with Title IV, New Source Review (NSR), state settlements, or state-specific rules were allowed in IPM to decide on the basis of economic efficiency whether to operate those controls. Further details on the EGU emissions inventory used for this proposal can be found in the IPM Documentation. Also note that as explained in section IV.A.3, the baseline used in this analysis assumes no CAIR. If EPA's base case analysis were to assume that reductions from CAIR would continue indefinitely, areas that are in attainment solely due to controls required by CAIR would again face nonattainment problems because the existing protection from upwind pollution would not be replaced. As explained in that section, EPA believes that this is the most appropriate baseline to use for purposes of determining whether an upwind state has an impact on a downwind monitoring site in violation of section 110(a)(2)(D).

Development of Future-Year Emissions Inventories for Mobile Inventories

Mobile source inventories of onroad and nonroad mobile emissions were created for 2012 and 2015 using a combination of the NMIM and draft MOVES models. Mobile source emissions were further interpolated between 2012 and 2015 to estimate 2014 emissions. Emissions for these years reflect onroad mobile control programs including the Light-Duty Vehicle Tier 2 Rule, the Onroad Heavy-Duty Rule, and the Mobile Source Air Toxics (MSAT) final rule. Nonroad mobile emissions reductions for these years include reductions to locomotives, various nonroad engines including diesel engines and various marine engine types, fuel sulfur content, and evaporative emissions standards. A more comprehensive list of control programs included for mobile sources is available in the EITSD.

The onroad emissions were primarily based on the NMIM monthly, county, process level emissions. For both 2012 and 2015, emissions from onroad gasoline sources were augmented with emissions based on the same preliminary version of MOVES as was used for 2005. MOVES-based emissions were computed for CO, NO_X, VOC, $PM_{2.5}$, and PM_{10}. The same MOVES-based $PM_{2.5}$ temperature adjustment factors were also applied as in 2005.

Nonroad mobile emissions were created only with NMIM using a consistent approach as was used for 2005, but emissions were calculated using NMIM future-year equipment population estimates and control programs for 2012 and 2014. Emissions from 2012 and 2015 were used for locomotives and category 1 and 2 (C1 and C2) commercial marine vessels, based on emissions published in OTAQ's Locomotive Marine Rule, Regulatory Impact Assessment, Chapter 3. For category 3 (C3) commercial marine vessels, a coordination strategy of emissions reductions is ongoing that includes NO_X, VOC, and CO reductions for new C3 engines as early as 2011 and fuel sulfur limits that could go into affect as early as 2012. However, given the uncertainty about the timing for parts of these emissions reductions and the fact that the 2012 modeling was conducted well in advance of the December 2009 publication of the rule, we have not used the controlled emissions in modeling supporting this proposal.

Development of Future-Year Emissions Inventories for Other Inventory Sources

Other inventory sources include nonEGU point sources, stationary nonpoint sources, and emissions in Canada and Mexico. Emissions from Canada and Mexico for all source sectors (including EGUs) in these countries were held constant for all cases. This approach reflects the unavailability of future-year emissions from Canada and Mexico for the future years of interest in time to support the modeling for this proposal.

The future year emissions for other sectors are described next. For all sector projections, EPA seeks comment on growth and control approaches, particularly where a control measure has not been included. The EITSD provides more details on these projections for additional review and we have included in the EITSD a table for the public to provide more detailed control data to EPA.

For nonEGU point sources, emissions were projected by including emissions reductions and increases from a variety of sources. For nonEGUs, emissions were not grown using economic growth projections and emissions reductions were applied through plant closures, refinery and other consent decrees, and reductions stemming from several MACT standards. Since aircraft at airports were treated as point emissions sources in the 2005 NEI v2, we also applied projection factors based on activity growth projected by the Federal Aviation Administration Terminal Area Forecast (TAF) system, published December 2008. Controls from the NO_X SIP Call were assumed to have been implemented by 2005 and captured in the 2005 NEI v2.

For stationary nonpoint sources, refueling emissions were projected using the refueling results from the NMIM runs performed for the onroad mobile sector. Portable fuel container emissions were projected using estimates from previous OTAQ rulemaking inventories. Emissions of ammonia and dust from animal operations were projected based on animal population data from the Department of Agriculture and EPA. Residential wood combustion was projected by replacement of obsolete woodstoves with new woodstoves and a 1 percent annual increase in fireplaces. Landfill emissions were projected using MACT controls. All other nonpoint sources were held constant between 2005 and the future years.

(3) Preparation of Emissions for AQ Modeling

The annual and summer day emissions inventory files were processed through the Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System version 2.6 to produce the gridded model-ready emissions for input to CAMx. Emissions processing using SMOKE was performed to create the hourly, gridded data of CAMx species required for air quality modeling for all sectors, including biogenic emissions. Additional information on the development of the emissions data sets for modeling is provided in the EITSD. Details about preparation of emissions for contribution modeling are described in the Transport Rule AQ Modeling TSD.

c. Preparation of Meteorological and Other Air Quality Modeling Inputs

The gridded meteorological input data for the entire year of 2005 were derived from simulations of the Pennsylvania State University/National Center for Atmospheric Research Mesoscale Model. This model, commonly referred to as MM5, is a limited-area, nonhydrostatic, terrain-following system that solves for the full set of physical and thermodynamic equations which govern atmospheric motions.[26] The meteorological outputs from MM5 were processed to create model-ready inputs for CMAQ using the MM5-to-CAMx preprocessor (ref CAMx user's guide).

The 2005 MM5 meteorological predictions for selected variables were compared to measurements as part of several performance evaluations of the predicted data. The evaluation approach included a combination of qualitative and quantitative analyses to assess the adequacy of the MM5 simulated fields. The qualitative aspects involved comparisons of the model-estimated synoptic patterns against observed patterns from historical weather chart archives. Additionally, the evaluations compared spatial patterns of monthly average rainfall and monthly maximum planetary boundary layer (PBL) heights. The operational evaluation included

[26] Grell, G., J. Dudhia, and D. Stauffer, 1994: A Description of the Fifth-Generation Penn State/NCAR Mesoscale Model (MM5), NCAR/TN–398+STR., 138 pp, National Center for Atmospheric Research, Boulder CO.

statistical comparisons of model/observed pairs (*e.g.*, mean normalized bias, mean normalized error, index of agreement, root mean square errors, etc.) for multiple meteorological parameters. For this portion of the evaluation, five meteorological parameters were investigated: Temperature, humidity, shortwave downward radiation, wind speed, and wind direction. The three individual MM5 evaluations are described elsewhere.[27] [28] [29] It was ultimately determined that the bias and error values associated with the 2005 meteorological data were generally within the range of past meteorological modeling results that have been used for air quality applications. Additional details on the meteorological inputs can be found in the AQMTSD.

As noted previously, the CAMx simulations for this proposal were performed using a spatial resolution of 12 x 12 km. The concentrations of pollutants transported into this eastern U.S. modeling region were obtained from air quality model simulations performed at coarser 36 x 36 km resolution for a modeling domain covering the lower 48 states and portions of northern Mexico and southern Canada. The 12 x 12 km model simulations were also initialized with air quality predictions from the coarse scale modeling. Pollutant concentrations at the boundaries of the coarse scale modeling domain were obtained from a three-dimensional global atmospheric chemistry model, the GEOSChem [30] model (standard version 7–04–11 [31]). The global GEOSChem model simulates atmospheric chemical and physical processes driven by assimilated meteorological observations from the NASA's Goddard Earth Observing System (GEOS). This model was run for 2005 with a grid resolution of 2.0 degrees x 2.5 degrees (latitude-longitude). The predictions were used to provide one-way dynamic boundary conditions at three-hour intervals and an initial concentration field for the coarse scale simulations.

d. Model Performance Evaluation for Ozone and $PM_{2.5}$

The 2005 base year model predictions for ozone and fine particulate sulfate, nitrate, organic carbon, elemental carbon, and crustal material were compared to measured concentrations in order to evaluate the performance of the modeling platform for replicating observed concentrations. This evaluation was comprised principally of statistical assessments of paired modeled and observed data. Details on the evaluation methodology and the calculation of performance statistics are provided in the AQMTSD. The results indicate that, overall, the predicted patterns and day-to-day variations in regional ozone levels are similar to what was observed with measured data. The normalized mean bias for 8-hour daily maximum ozone concentrations was −2.9 percent and the normalized mean error was 13.2 percent for the months of May through September 2005, based on an aggregate of observed-predicted pairs within the 12 km modeling domain. The two $PM_{2.5}$ species that are most relevant for this proposal are sulfate and nitrate. For the summer months of June though August, when observed sulfate concentrations are highest in the East, the model predictions of 24-hour average sulfate were lower than the corresponding measured values by 7 percent at urban sites and by 9 to 10 percent at rural sites in the IMPROVE [32] and CASTNET [33] monitoring networks, respectively. For the winter months of December through February, when observed nitrate concentrations are highest in the East, the model predictions of 24-hour average particulate nitrate were lower than the corresponding measured values by 12 percent at urban sites and by 4 percent at rural sites in the IMPROVE monitoring network. The model performance statistics by season for ozone and $PM_{2.5}$ component species are provided in the AQMTSD.

2. How did EPA project future nonattainment and maintenance for annual $PM_{2.5}$, 25-Hour $PM_{2.5}$, and 8-hour ozone?

In this section we describe the approach for projecting future concentrations of ozone and $PM_{2.5}$ to identify locations that are expected to be nonattainment or have a maintenance problem in 2012. The nonattainment and maintenance locations are based on projections of future air quality at existing ozone and $PM_{2.5}$ monitoring sites. These sites are used as the "receptors" for quantifying the contributions of emissions in upwind states to nonattainment and maintenance in downwind locations. For this analysis we are using the air quality modeling results in a "relative" sense to project future concentrations. In this approach, the ratio of future year model predictions to base year model predictions are used to adjust ambient measured data up or down depending on the relative (percent) change in model predictions for each location.

a. How did EPA process ambient ozone and $PM_{2.5}$ data for the purpose of projecting future year concentrations?

In this analysis we use measurements of ambient ozone and $PM_{2.5}$ data that come from monitoring networks consisting of more than one thousand ozone monitors and one thousand $PM_{2.5}$ monitors located across the country. The monitors are sited according to the spatial and temporal nature of ozone and $PM_{2.5}$, and to best represent the actual air quality in the United States. The ambient data used in this analysis were obtained from EPA's Air Quality System (AQS).

In order to use the ambient data, the raw measurements must be processed into a form pertinent for useful interpretations. For this action, the ozone data were processed consistent with the formats associated with the NAAQS for ozone. The resulting estimates are used to indicate the level of air quality relative to the NAAQS. For ozone air quality indicators, we developed estimates for the 1997 8-hour ozone standard. The level of the 1997 8-hour O3 NAAQS is 0.08 ppm. The 8-hour ozone standard is not met if the 3-year average of the annual 4th highest daily maximum 8-hour O3 concentration is greater than 0.08 ppm (0.085 ppm when rounded up). This 3-year average is referred to as the design value.

The $PM_{2.5}$ ambient data were processed consistent with the formats associated with the NAAQS for $PM_{2.5}$. The resulting estimates are used to

[27] Baker K. and P. Dolwick. Meteorological Modeling Performance Evaluation for the Annual 2005 Eastern U.S. 12-km Domain Simulation, USEPA/OAQPS, February 2, 2009.

[28] Baker K. and P. Dolwick. Meteorological Modeling Performance Evaluation for the Annual 2005 Western U.S. 12-km Domain Simulation, USEPA/OAQPS, February 2, 2009.

[29] Baker K. and P. Dolwick. Meteorological Modeling Performance Evaluation for the Annual 2005 Continental U.S. 36-km Domain Simulation, USEPA/OAQPS, February 2, 2009.

[30] Yantosca, B., 2006. GEOS–CHEMv7–04–11 User's Guide, Atmospheric Chemistry Modeling Group, Harvard University, Cambridge, MA, March 05, 2006.

[31] Henze, D.K., J.H. Seinfeld, N.L. Ng, J.H. Kroll, T-M. Fu, D.J. Jacob, C.L. Heald, 2008. Global modeling of secondary organic aerosol formation from aromatic hydrocarbons: high-vs. low-yield pathways. *Atmos. Chem. Phys.*, 8, 2405–2420.

[32] *I*nteragency *M*onitoring of *PRO*tected *V*isual *E*nvironments (IMPROVE). Debell, L.J., et. al. Spatial and Seasonal Patterns and Temporal Variability of Haze and its Constituents in the United States: Report IV. November 2006.

[33] Clean Air Status and Trends Network (CASTNET) 2005 Annual Report. EPA Office of Air and Radiation, Clean Air Markets Division. Washington, DC. December 2006.

indicate the level of air quality relative to the NAAQS. For $PM_{2.5}$, we evaluated concentrations of both the annual average $PM_{2.5}$ NAAQS and the 24-hour $PM_{2.5}$ NAAQS. The annual $PM_{2.5}$ standard is met when the 3-year average of the annual mean concentration is 15.0 μg/m^3 or less. The 3-year average annual mean concentration is computed at each site by averaging the daily Federal Reference Method (FRM) samples by quarter, averaging these quarterly averages to obtain an annual average, and then averaging the three annual averages. The 3-year average annual mean concentration is referred to as the annual design value.

The 24-hour average standard is met when the 3-year average of the annual 98th percentile $PM_{2.5}$ concentration is 35 μg/m^3 or less. The 3-year average mean 98th percentile concentration is computed at each site by averaging the 3 individual annual 98th percentile values at each site. The 3-year average 98th percentile concentration is referred to as the 24-hour average design value.

As described later, the approach for projecting future ozone and $PM_{2.5}$ design values involved the projection of an average of up to 3 design value periods which include the years 2003–2007 (design values for 2003–2005, 2004–2006, and 2005–2007). The average of the 3 design values creates a "5-year weighted average" value. The 5-year weighted average values were then projected to the future years that were analyzed for this proposed rule. The 2003–2005, 2004–2006, and 2005–2007 design values are accessible at *http://www.epagov/airtrends/values.html.*

The procedures for projecting annual average $PM_{2.5}$ and 8-hour ozone conform to the methodology in the final attainment demonstration modeling guidance [34]. In the CAIR analysis, EPA did not project 24-hour $PM_{2.5}$ design values [35]. The analysis for this proposed rule, in contrast, uses the 24-hour $PM_{2.5}$ methodology outlined in the modeling guidance.

b. Projection of Future Annual and 24-Hour $PM_{2.5}$ Nonattainment and Maintenance

Annual $PM_{2.5}$ modeling was performed for the 2005 base year emissions and for the 2012 base case as part of the approach for projecting which locations (*i.e.*, monitoring sites) are expected to be in nonattainment and/or have difficulty maintaining the $PM_{2.5}$ standards in 2012. We refer to these areas as nonattainment sites and maintenance sites respectively.

In general, the projection methodology involves using the model in a relative sense to estimate the change in $PM_{2.5}$ between 2005 and the future 2012 base case as recommended in the modeling guidance. Rather than use the absolute model-predicted future year ozone and $PM_{2.5}$ concentrations, the base year and future year predictions are used to calculate a (relative) percent change in ozone and $PM_{2.5}$ concentrations. For a particular location, the percent change in modeled concentration is multiplied by the corresponding observed base period ambient concentration to estimate the future year design value for that location. The use of observed ambient data as part of the calculation helps to constrain the future year design value predictions, even if the absolute model concentrations are over-predicted or under-predicted.

Concentrations of $PM_{2.5}$ in 2012 were estimated by applying the 2005 to 2012 relative change in model-predicted $PM_{2.5}$ species to the (2003–2007) $PM_{2.5}$ design values. The choice of base period design values is consistent with EPA's modeling guidance which recommends using the average of the three design value periods centered about the emissions projection year. Since 2005 was the base emissions year, we used the design value for 2003–2005, 2004–2006, and 2005–2007 to represent the base period $PM_{2.5}$ concentrations. For each FRM $PM_{2.5}$ monitoring site, all valid design values (up to 3) from this period were averaged together. Since 2005 is included in all three design value periods, this has the effect of creating a 5-year weighted average, where the middle year is weighted 3 times, the 2nd and 4th years are weighted twice, and the 1st and 5th years are weighted once. We refer to this as the 5-year weighted average concentration.

The 5-year weighted average concentrations were used to project concentrations for the 2012 base case in order to determine which monitoring sites are expected to be nonattainment in this future year. We projected 2012 design values for each of 3 year periods (*i.e.*, 2003–2005, 2004–2006, and 2003–2007) and used the highest of these projections to determine which sites are expected to have maintenance problems in 2012.

For the analysis of both nonattainment and maintenance, monitoring sites were included in the analysis if they had at least one complete design value in the 2003–2007 period.[36] There were 721 monitoring sites in the 12 km modeling domain which had at least one complete design value period for the annual $PM_{2.5}$ NAAQS, and 736 sites which met this criteria for the 24-hour NAAQS.[37]

EPA followed the procedures recommended in the modeling guidance for projecting $PM_{2.5}$ by projecting individual $PM_{2.5}$ component species and then summing these to calculate the concentration of total $PM_{2.5}$. The model predictions are used in a relative sense to estimate changes expected to occur in each of the major $PM_{2.5}$ species. The $PM_{2.5}$ species are sulfate, nitrate, ammonium, particle bound water, elemental carbon, salt, other primary $PM_{2.5}$, and organic aerosol mass by difference. Organic aerosol mass by difference is defined as the difference between FRM $PM_{2.5}$ and the sum of the other components. The procedure for calculating future year $PM_{2.5}$ design values is called the SMAT. The SMAT approach is codified in a software tool available from EPA called MATS. The software (including documentation) is available at: *http://www.epa.gov/scram001/modelingapps_mats.htm.*

(1) Methodology for Projecting Future Annual $PM_{2.5}$ Nonattainment and Maintenance

The following is a brief summary of the future year annual $PM_{2.5}$ calculations. Additional details are provided in the modeling guidance, MATS documentation, and the AQMTSD.

We are using the base period (*i.e.*, 2003 2007) FRM data for projecting future design values since these data are used to determine attainment status. In order to apply SMAT to the FRM data, information on $PM_{2.5}$ speciation is needed for the location of each FRM monitoring site. Since co-located $PM_{2.5}$ speciation data are only available at about 15 percent of FRM monitoring sites, spatial interpolation techniques are used to calculate species concentrations for each FRM monitoring site. Speciation data from the IMPROVE and Chemical Speciation Network

[34] U.S. EPA, 2007: Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze; Office of Air Quality Planning and Standards, Research Triangle Park, NC.

[35] CAIR was promulgated in 2005 before the 35 ug/m^3 $PM_{2.5}$ NAAQS was finalized in 2006. Since there were no violations in the eastern United States (base or future year) of the 1997 65 ug/m3 NAAQS, it was not necessary to project 24 $PM_{2.5}$ values as part of the modeling for CAIR.

[36] If there is only one complete design value, then the nonattainment and maintenance design values are the same.

[37] Design values were only used if they were deemed to be officially complete based on CFR 40 part 50 appendix N. The completeness criteria for the annual and 24-hour $PM_{2.5}$ NAAQS are different. Therefore, there are fewer complete sites for the annual NAAQS.

(CSN) were interpolated to each FRM monitor location using the Voronoi Neighbor Averaging (VNA) technique (using MATS). Additional information on the VNA interpolation techniques and data handling procedures can be found in the MATS User's Guide. After the species fractions are calculated for each FRM site, the following procedures were used to estimate future year design values:

Step 1: Calculate quarterly mean concentrations for each of the major species components of $PM_{2.5}$ (*i.e.*, sulfate, nitrate, ammonium, elemental carbon, organic carbon mass, particle bound water, salt, and blank mass). This is done by multiplying the monitored quarterly mean concentration of FRM-derived total $PM_{2.5}$ by the monitored fractional composition of $PM_{2.5}$ species for each quarter averaged over 3 years [38] (*e.g.*, 20 percent sulfate fraction multiplied by 15 $\mu g/m^3$ $PM_{2.5}$ equals 3 $\mu g/m^3$ sulfate).

Step 2: For each quarter, calculate the ratio of future year to base year model predictions for each of the component species. The result is a set of species-specific relative response factors (RRF) (*e.g.*, assume that the model-predicted 2005 base year sulfate for a particular location is 10.0 $\mu g/m^3$ and the 2012 future concentration is 8.0 $\mu g/m^3$, then RRF for sulfate is 0.8). The RRFs are calculated based on the modeled concentrations averaged over the nine grid cells [39] centered at the location of the monitor.

Step 3: For each quarter and each of the species, multiply the base year quarterly mean component concentration (Step 1) by the species-specific RRF obtained in Step 2. This results in an estimated future year quarterly mean concentration for each species (*e.g.*, 3 $\mu g/m^3$ sulfate multiplied by 0.8 equals a future sulfate concentration of 2.4 $\mu g/m^3$).

Step 4: The future year concentrations for the remaining species are then calculated.[40] The future year ammonium is calculated based on the calculated future year sulfate and nitrate concentrations, using a constant value for the degree of neutralization of sulfate (from the ambient data). The future year particle bound water concentration is calculated from an empirical formula. The inputs to the formula are the future year concentrations of sulfate, nitrate, and ammonium (from step 3).

Step 5: Average the four quarterly mean future concentrations to obtain the future year annual design value concentration for each of the component species. Sum the species concentrations to obtain the future year annual average design value for $PM_{2.5}$.

Step 6: Calculate the maximum future design value by processing each of the three base design value periods (2003–2005, 2004–2006, and 2005–2007) separately. The highest of the three future values is the maximum design value. The maximum design values are used to determine future year maintenance sites.

The preceding procedures for determining future year $PM_{2.5}$ concentrations were applied for each FRM site. The calculated annual $PM_{2.5}$ design values are truncated (*i.e.*, discarded) after the second decimal place.[41] This is consistent with the truncation and rounding procedures for the annual $PM_{2.5}$ NAAQS. Any value that is greater than or equal to 15.05 $\mu g/m^3$ is rounded to 15.1 $\mu g/m^3$ and is considered to be violating the NAAQS. Thus, sites with future year annual $PM_{2.5}$ design values of 15.05 $\mu g/m^3$ or greater, based on the projection of 5-year weighted average concentrations, are predicted to be nonattainment sites. Sites with future year maximum design values of 15.05 $\mu g/m^3$ or greater are predicted to be maintenance sites. Note that nonattainment sites are also maintenance sites because the maximum design value is always greater than or equal to the 5-year weighted average. For ease of reference we use the term "nonattainment sites" to refer to those sites that are projected to exceed the NAAQS based on both the average and maximum design values. Those sites that are projected to be attainment based on the average design value but exceed the NAAQS based on the maximum design value are referred to as maintenance sites. The monitoring sites that we project to be nonattainment and/or maintenance for the annual $PM_{2.5}$ NAAQS in the 2012 base case are the nonattainment/maintenance receptors used for assessing the contribution of emissions in upwind states to downwind nonattainment and maintenance of the annual $PM_{2.5}$ NAAQS as part of this proposal.

Table IV.C–7 contains the 2003–2007 base case period average and maximum annual $PM_{2.5}$ design values and the corresponding 2012 base case average and maximum design values for sites projected to be nonattainment of the annual $PM_{2.5}$ NAAQS in 2012. Table IV.C–8 contains this same information for projected 2012 maintenance sites.

TABLE IV.C–7—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE ANNUAL $PM_{2.5}$ DESIGN VALUES ($\mu G/M^3$) AT PROJECTED NONATTAINMENT SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
10730023	Alabama	Jefferson	18.48	18.67	17.15	17.33
10732003	Alabama	Jefferson	17.07	17.45	15.99	16.35
130210007	Georgia	Bibb	16.47	16.78	15.33	15.62
130630091	Georgia	Clayton	16.47	16.71	15.07	15.29
131210039	Georgia	Fulton	17.43	17.47	16.01	16.04
170310052	Illinois	Cook	15.75	16.02	15.16	15.43
171191007	Illinois	Madison	16.72	17.01	16.56	16.85
171630010	Illinois	Saint Clair	15.58	15.74	15.48	15.63
180190006	Indiana	Clark	16.40	16.60	15.96	16.16
180372001	Indiana	Dubois	15.18	15.68	15.07	15.57
180970078	Indiana	Marion	15.26	15.43	15.18	15.36

[38] For this analysis, species fractions were calculated using an average of FRM and speciation data for the 2004–2006 time period. This was deemed to be representative of the 2005 base year.

[39] The modeling guidance recommends calculating annual $PM_{2.5}$ RRFs using a 3 x 3 grid cell array (9 grid cells) for a model resolution of 12km.

[40] All of the calculations and assumptions are consistent with the default MATS settings (as described in the MATS user's guide and the photochemical modeling guidance). Additionally, we did not explicitly model salt and therefore the salt concentration was held constant from the base to future. Blank mass was assumed to be a constant mass of 0.5 $\mu g/m^3$ in both the base and future year.

[41] For example, a calculated annual average concentration of 14.94753 * * * becomes 14.94 when digits beyond two places to the right are truncated.

TABLE IV.C–7—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE ANNUAL $PM_{2.5}$ DESIGN VALUES (μG/M3) AT PROJECTED NONATTAINMENT SITES—Continued

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
180970081	Indiana	Marion	16.05	16.36	15.93	16.25
180970083	Indiana	Marion	15.90	16.27	15.77	16.15
211110043	Kentucky	Jefferson	15.53	15.75	15.19	15.41
261630015	Michigan	Wayne	15.88	16.40	15.05	15.55
261630033	Michigan	Wayne	17.50	18.16	16.57	17.19
390170016	Ohio	Butler	15.74	16.11	15.25	15.61
390350038	Ohio	Cuyahoga	17.37	18.1	16.26	16.95
390350045	Ohio	Cuyahoga	16.47	16.98	15.42	15.91
390350060	Ohio	Cuyahoga	17.11	17.66	16.02	16.55
390610014	Ohio	Hamilton	17.29	17.53	16.69	16.93
390610042	Ohio	Hamilton	16.85	17.25	16.33	16.71
390610043	Ohio	Hamilton	15.55	15.82	15.05	15.32
390617001	Ohio	Hamilton	16.17	16.56	15.65	16.03
390618001	Ohio	Hamilton	17.54	17.90	16.93	17.27
420030064	Pennsylvania	Allegheny	20.31	20.75	18.90	19.31
420031301	Pennsylvania	Allegheny	16.26	16.57	15.13	15.42
420070014	Pennsylvania	Beaver	16.38	16.45	15.23	15.30
420710007	Pennsylvania	Lancaster	16.55	17.46	15.19	16.01
421330008	Pennsylvania	York	16.52	17.25	15.25	15.94
540110006	West Virginia	Cabell	16.30	16.57	15.25	15.50
540391005	West Virginia	Kanawha	16.52	16.59	15.28	15.34

TABLE IV.C–8—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE ANNUAL $PM_{2.5}$ DESIGN VALUES (μ/M3) AT PROJECTED MAINTENANCE-ONLY SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
170313301	Illinois	Cook	15.24	15.59	14.73	15.06
170316005	Illinois	Cook	15.48	16.07	14.92	15.48
211110044	Kentucky	Jefferson	15.31	15.47	14.93	15.09
360610056	New York	New York	16.18	17.02	14.98	15.74
390350027	Ohio	Cuyahoga	15.46	16.13	14.50	15.13
390350065	Ohio	Cuyahoga	15.97	16.44	14.96	15.40
390610040	Ohio	Hamilton	15.50	15.88	15.03	15.40
390811001	Ohio	Jefferson	16.51	17.17	14.95	15.54
391130032	Ohio	Montgomery	15.54	15.92	15.01	15.37
391510017	Ohio	Stark	16.15	16.59	14.99	15.40
420110011	Pennsylvania	Berks	15.82	16.19	14.77	15.11
482011035	Texas	Harris	15.42	15.84	14.74	15.14
540030003	West Virginia	Berkeley	15.93	16.19	14.95	15.20
540090005	West Virginia	Brooke	16.52	16.80	14.95	15.22
540291004	West Virginia	Hancock	15.76	16.64	14.34	15.15
540490006	West Virginia	Marion	15.03	15.25	14.96	15.18

(2) Methodology for Projecting Future 24-Hour $PM_{2.5}$ Nonattainment and Maintenance

The following is a brief summary of the procedures used for calculating future year 24-hour $PM_{2.5}$ design values. Additional details are provided in the modeling guidance, MATS documentation, and the AQMTSD. Similar to the annual $PM_{2.5}$ calculations, we are using the 2003–2007 base period FRM data for projecting future year design values. The 24-hour $PM_{2.5}$ calculations are computationally similar to the annual average calculations. The main difference is that the base period 24-hour 98th percentile $PM_{2.5}$ concentrations are projected to the future year, instead of the annual average concentrations. Also, the $PM_{2.5}$ species fractions and relative response factors are calculated from observed and modeled high concentration days, instead of quarterly average data.

Both the annual $PM_{2.5}$ and 24-hour $PM_{2.5}$ calculations are performed on a calendar quarter basis. Since all years and quarters are averaged together in the annual $PM_{2.5}$ calculations, the individual years can be averaged together early in the calculations. However, in the 24-hour $PM_{2.5}$ calculations, only the high quarter from each year is used in the final calculations. This represents the 98th percentile value, which can come from any of the 4 quarters in any year. Therefore all quarters and years must be carried through to near the end of the calculations when the individual future year high quarter values are selected. To calculate final future year design values, the high quarter for each year is identified and then a five year weighted average of the high quarters for each site was calculated to derive the future year design value.

The following are the steps followed for calculating the 2012 base case 24-hour $PM_{2.5}$ design values:

Step 1: At each FRM monitoring site, we identify the maximum 24-hour $PM_{2.5}$ concentration in each quarter that is less than or equal to the 98th percentile value over the entire year. This results in a data set for each year (for up to 5 years) for each site containing one quarter with the observed 98th percentile value and three quarters with the maximum highest values from each quarter that are less than or equal to the 98th percentile value for the year. All 20 quarters (*i.e.*, 4 quarters in each of 5 years) of data are carried through the calculations until the high future year quarter value is identified in step 6.

Step 2: In this step we calculate quarterly ambient concentrations on "high" [42] days for each of the major component species of $PM_{2.5}$ (sulfate, nitrate, ammonium, elemental carbon, organic carbon mass, particle bound water, salt, and blank mass). This calculation is performed by multiplying the monitored concentrations of FRM-derived total $PM_{2.5}$ mass on the 10 percent highest days from each quarter, by the monitored fractional composition of $PM_{2.5}$ species on the 10 percent highest $PM_{2.5}$ days for each quarter, averaged over 3 years [43] (*e.g.*, 20 percent sulfate fraction multiplied by 40 μg/m³ $PM_{2.5}$ equals 8 μg/m³ sulfate).

Step 3: For each quarter, we calculate the ratio of future year (*i.e.*, 2012) to base year (*i.e.*, 2005) predictions for each component species for the top 10 percent of days based on predicted concentrations of 24-hour $PM_{2.5}$. The result is a set of species-specific relative response factors (RRF) for the high $PM_{2.5}$ days in each quarter (*e.g.*, assume that the 2005 predicted sulfate concentration on the 10 percent highest $PM_{2.5}$ days for a quarter for a particular location is 20 μg/m³ and the 2012 base case concentration is 16 μg/m³, then RRF for sulfate is 0.8). The RRFs are calculated based on the modeled concentrations at the single grid cell where the monitor is located.

Step 4: For each quarter, we multiply the quarterly species concentration (step 2) by the quarterly [44] species-specific RRF obtained in step 3. This leads to an estimated future quarterly concentration for each component. (*e.g.*, 21.0 μg/m³ nitrate × 0.75 = future nitrate of 15.75 μg/m³).

Step 5: The future year concentrations for the remaining species are then calculated.[45] The future year ammonium is calculated based on the calculated future year sulfate and nitrate concentrations, using a constant value for the degree of neutralization of sulfate (from the ambient data). The future year particle bound water concentration is calculated from an empirical formula. The inputs to the formula are the calculated future year concentrations of sulfate, nitrate, and ammonium (from step 4).

Step 6: We sum the species concentrations to obtain quarterly $PM_{2.5}$ values. This step is repeated for each quarter and for each of the 5 years of ambient data. The highest daily value (from the 4 quarterly values) for each year at each monitor is considered to be the estimated future year 98th percentile 24-hour design value for that year.

Step 7: The estimated 98th percentile values for each of the 5 years are averaged over 3 year intervals to create the 3 year average design values. These design values are averaged to create a 5 year weighted average for each monitoring site.

Step 8: The maximum future design value is calculated by following the previous steps for each of the three base design value periods (2003–2005, 2004–2006, and 2005–2007) separately. The highest of the three future values is the maximum design value. This maximum value is used to identify the 24-hour $PM_{2.5}$ maintenance receptors.

The preceding procedures for determining future year 24-hour $PM_{2.5}$ concentrations were applied for each FRM site. The 24-hour $PM_{2.5}$ design values are truncated after the first decimal place. This approach is consistent with the truncation and rounding procedures for the 24-hour $PM_{2.5}$ NAAQS. Any value that is greater than or equal to 35.5 μg/m³ is rounded to 36 μg/m³ and is violating the NAAQS. Sites with future year 5 year weighted average design values of 35.5 μg/m³ or greater, based on the projection of 5-year weighted average concentrations, are predicted to be nonattainment. Sites with future year maximum design values of 35.5 μg/m³ or greater are predicted to be maintenance sites. Note that nonattainment sites for the 24-hour NAAQS are also maintenance sites because the maximum design value is always greater than or equal to the 5-year weighted average. For ease of reference we use the term "nonattainment sites" to refer to those sites that are projected to exceed the NAAQS based on both the average and maximum design values. Those sites that are projected to be attainment based on the average design value but exceed the NAAQS based on the maximum design value are referred to as maintenance sites. The monitoring sites that we project to be nonattainment and/or maintenance for the 24-hour $PM_{2.5}$ NAAQS in the 2012 base case are the nonattainment/maintenance receptors used for assessing the contribution of emissions in upwind states to downwind nonattainment and maintenance of 24-hour $PM_{2.5}$ NAAQS as part of this proposal.

Table IV.C–9 contains the 2003–2007 base period average and maximum 24-hour $PM_{2.5}$ design values and the 2012 base case average and maximum design values for sites projected to be 2012 nonattainment of the 24-hour $PM_{2.5}$ NAAQS in 2012. Table IV.C–10 contains this same information for projected 2012 24-hour maintenance sites.

TABLE IV.C–9—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 24-HOUR $PM_{2.5}$ DESIGN VALUES (μG/M³) AT PROJECTED NONATTAINMENT SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
10730023	Alabama	Jefferson	44.0	44.2	40.0	40.7
10732003	Alabama	Jefferson	40.3	40.8	38.1	38.9
90091123	Connecticut	New Haven	38.3	40.3	35.7	36.6
170310052	Illinois	Cook	40.2	41.4	38.5	39.7

[42] High ambient data and model days were defined as the top 10 percent days in each quarter based on 24-hour concentrations of $PM_{2.5}$.

[43] For this analysis, species fractions were calculated using an average of FRM and speciation data for the 2004–2006 time period. This was deemed to be representative of the 2005 modeling year.

[44] Since there is only one modeled base year, there are a single set of four quarterly RRFs. The modeled quarterly RRF for quarter 1 is multiplied by the ambient data for quarter 1 for each of the 5 years of ambient data. The same procedure is applied for the other 3 quarters.

[45] All of the calculations and assumptions are consistent with the default MATS settings (as described in the MATS user's guide and the photochemical modeling guidance). Additionally, we did not explicitly model salt and therefore the salt concentration was held constant from the base to future. Blank mass was assumed to be a constant mass of 0.5 ug/m³ in both the base and future year.

TABLE IV.C–9—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 24-HOUR $PM_{2.5}$ DESIGN VALUES (μG/M³) AT PROJECTED NONATTAINMENT SITES—Continued

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
170310057	Illinois	Cook	37.3	38.6	35.7	37.0
170310076	Illinois	Cook	38.0	39.1	36.3	37.3
170311016	Illinois	Cook	43.0	46.3	41.0	44.1
170312001	Illinois	Cook	37.7	40.6	35.6	38.2
170313103	Illinois	Cook	39.6	40.3	38.1	38.7
170313301	Illinois	Cook	40.2	43.3	38.2	41.0
170316005	Illinois	Cook	39.1	41.8	37.4	39.8
171190023	Illinois	Madison	37.3	38.1	39.4	40.2
171191007	Illinois	Madison	39.1	40.1	40.0	40.6
171192009	Illinois	Madison	34.9	35.9	37.2	38.2
171193007	Illinois	Madison	34.0	34.6	36.5	37.3
180190006	Indiana	Clark	37.5	39.4	38.1	40.2
180372001	Indiana	Dubois	35.3	36.9	36.5	38.0
180830004	Indiana	Knox	35.9	36.3	35.9	36.5
180890022	Indiana	Lake	38.9	44.0	37.3	42.1
180890026	Indiana	Lake	38.4	41.3	36.3	39.3
180970042	Indiana	Marion	34.2	35.3	36.3	37.2
180970043	Indiana	Marion	38.4	39.9	40.5	42.0
180970066	Indiana	Marion	38.3	39.6	40.3	41.8
180970078	Indiana	Marion	36.6	37.6	38.7	39.7
180970079	Indiana	Marion	35.6	36.7	37.2	38.3
180970081	Indiana	Marion	38.2	39.2	40.1	41.1
180970083	Indiana	Marion	36.6	37.0	39.0	39.3
181570008	Indiana	Tippecanoe	35.6	36.7	35.9	36.9
191630019	Iowa	Scott	37.1	37.1	36.8	36.8
210590005	Kentucky	Daviess	33.8	33.8	37.0	37.0
211110043	Kentucky	Jefferson	35.4	36.1	35.8	36.4
211110044	Kentucky	Jefferson	36.1	36.6	36.0	36.5
211110048	Kentucky	Jefferson	36.4	37.2	35.6	36.4
245100040	Maryland	Baltimore City	39.0	40.9	36.3	38.3
245100049	Maryland	Baltimore City	38.1	38.1	35.5	35.5
261150005	Michigan	Monroe	38.8	39.6	37.0	38.0
261250001	Michigan	Oakland	39.9	40.4	37.9	38.4
261470005	Michigan	St. Clair	39.6	40.6	38.4	39.4
261610008	Michigan	Washtenaw	39.4	40.8	38.1	39.8
261630015	Michigan	Wayne	40.1	40.6	38.5	39.1
261630016	Michigan	Wayne	42.9	45.4	40.6	43.0
261630019	Michigan	Wayne	40.9	41.4	38.6	39.1
261630033	Michigan	Wayne	43.8	44.2	42.1	42.6
261630036	Michigan	Wayne	37.1	37.9	36.3	36.9
290990012	Missouri	Jefferson	33.4	34.2	35.7	36.5
291831002	Missouri	Saint Charles	33.1	34.7	35.5	37.1
295100007	Missouri	St. Louis City	33.1	33.5	36.0	36.3
295100087	Missouri	St. Louis City	34.3	34.7	36.4	36.9
340171003	New Jersey	Hudson	39.0	40.5	35.7	36.1
340172002	New Jersey	Hudson	41.4	41.4	38.2	38.2
340390004	New Jersey	Union	40.4	41.4	36.7	37.2
360050080	New York	Bronx	38.8	40.2	35.9	36.2
360610056	New York	New York	39.7	40.6	37.1	38.0
360610128	New York	New York	39.4	41.8	36.2	38.0
390170003	Ohio	Butler	39.2	41.1	40.3	42.3
390170016	Ohio	Butler	37.1	37.7	37.5	37.8
390170017	Ohio	Butler	37.9	37.9	38.5	38.5
390171004	Ohio	Butler	37.1	38.1	37.8	38.6
390350038	Ohio	Cuyahoga	44.2	47.0	41.2	44.0
390350045	Ohio	Cuyahoga	38.5	41.5	36.0	39.0
390350060	Ohio	Cuyahoga	42.1	45.7	39.4	42.8
390350065	Ohio	Cuyahoga	38.6	41.0	36.5	38.9
390490024	Ohio	Franklin	38.5	39.7	36.6	37.6
390490025	Ohio	Franklin	38.4	39.1	36.1	36.4
390610006	Ohio	Hamilton	37.6	37.6	38.0	38.0
390610014	Ohio	Hamilton	38.2	39.4	37.5	38.5
390610040	Ohio	Hamilton	36.7	37.7	35.8	36.8
390610042	Ohio	Hamilton	37.3	38.2	37.2	38.0
390610043	Ohio	Hamilton	35.9	36.2	36.0	36.4
390617001	Ohio	Hamilton	38.8	39.6	37.7	38.1
390618001	Ohio	Hamilton	40.6	40.9	39.6	40.3
390811001	Ohio	Jefferson	41.9	45.5	36.5	39.9
391130032	Ohio	Montgomery	37.8	40.0	36.3	38.5

TABLE IV.C–9—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 24-HOUR $PM_{2.5}$ DESIGN VALUES (µG/M³) AT PROJECTED NONATTAINMENT SITES—Continued

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
391530017	Ohio	Summit	38.0	39.6	35.6	37.2
420030008	Pennsylvania	Allegheny	39.4	39.9	35.9	36.3
420030064	Pennsylvania	Allegheny	64.2	68.2	58.8	62.3
420030093	Pennsylvania	Allegheny	45.6	51.5	41.1	46.2
420030116	Pennsylvania	Allegheny	42.5	42.5	37.1	37.1
420031008	Pennsylvania	Allegheny	41.3	42.8	38.0	39.3
420031301	Pennsylvania	Allegheny	40.3	42.4	36.6	38.6
420070014	Pennsylvania	Beaver	43.4	44.6	37.7	39.1
420110011	Pennsylvania	Berks	37.7	39.1	35.8	37.0
420210011	Pennsylvania	Cambria	39.0	39.4	40.3	40.7
420430401	Pennsylvania	Dauphin	38.0	39.0	35.7	37.1
420710007	Pennsylvania	Lancaster	40.8	44.0	37.7	40.1
421330008	Pennsylvania	York	38.2	40.7	35.9	38.8
471251009	Tennessee	Montgomery	36.3	37.5	36.6	37.9
540090011	West Virginia	Brooke	43.9	44.9	39.9	40.8
550790010	Wisconsin	Milwaukee	38.6	40.0	37.7	39.0
550790026	Wisconsin	Milwaukee	37.3	41.3	36.3	40.1
550790043	Wisconsin	Milwaukee	39.9	40.8	38.8	39.7
550790099	Wisconsin	Milwaukee	37.7	38.7	36.8	37.7

TABLE IV.C–10—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 24-HOUR $PM_{2.5}$ DESIGN VALUES (µG/M³) AT PROJECTED MAINTENANCE-ONLY SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
110010041	Washington DC	Washington DC	36.3	37.8	34.0	35.6
110010042	Washington DC	Washington DC	34.9	37.0	33.0	35.6
170310022	Illinois	Cook	36.6	38.6	34.9	36.6
170310050	Illinois	Cook	36.1	38.0	34.1	35.8
170314007	Illinois	Cook	34.3	36.4	33.6	35.7
171630010	Illinois	Saint Clair	33.7	34.1	35.3	35.9
171971002	Illinois	Will	36.4	37.1	35.1	35.8
180390003	Indiana	Elkhart	34.4	36.3	33.8	35.6
180431004	Indiana	Floyd	33.2	34.5	34.3	35.7
181670023	Indiana	Vigo	34.8	36.1	35.1	36.5
191390015	Iowa	Muscatine	36.0	37.7	34.5	36.0
210290006	Kentucky	Bullitt	34.6	35.8	35.0	36.3
211451004	Kentucky	McCracken	33.6	35.9	34.4	36.8
212270007	Kentucky	Warren	33.1	35.1	33.7	36.3
240031003	Maryland	Anne Arundel	35.5	37.4	33.8	36.7
245100035	Maryland	Baltimore (City)	37.7	39.2	34.7	35.5
261630001	Michigan	Wayne	37.8	40.1	35.4	37.8
295100085	Missouri	St. Louis City	33.2	33.8	35.3	35.7
360610062	New York	New York	38.8	41.6	35.3	37.0
360610079	New York	New York	37.9	40.2	34.2	36.4
390350027	Ohio	Cuyahoga	36.6	38.8	34.5	36.6
390350034	Ohio	Cuyahoga	36.5	37.9	33.7	35.7
390810017	Ohio	Jefferson	40.7	42.4	35.3	36.8
390950024	Ohio	Lucas	36.3	38.6	34.2	36.5
390950026	Ohio	Lucas	34.9	36.7	33.6	35.6
390990014	Ohio	Mahoning	36.8	38.2	34.2	35.8
391130031	Ohio	Montgomery	35.7	37.1	34.3	35.6
391351001	Ohio	Preble	32.8	33.9	34.3	35.5
391550007	Ohio	Trumbull	36.2	37.8	33.9	35.6
420030095	Pennsylvania	Allegheny	38.7	40.7	34.3	36.6
420033007	Pennsylvania	Allegheny	37.5	43.1	33.8	38.5
420410101	Pennsylvania	Cumberland	38.0	40.2	35.3	37.0
421255001	Pennsylvania	Washington	38.1	39.9	33.9	35.5
471650007	Tennessee	Sumner	33.6	34.5	35.1	36.0
540090005	West Virginia	Brooke	39.4	41.5	33.9	36.1
550250047	Wisconsin	Dane	35.5	36.9	35.1	36.1
550790059	Wisconsin	Milwaukee	35.5	37.0	34.8	36.3
551330027	Wisconsin	Waukesha	35.4	36.2	34.9	35.6

(3) Methodology for Projecting Future 8-Hour Ozone Nonattainment and Maintenance

The following is a brief summary of the future year 8-hour average ozone calculations. Additional details are provided in the modeling guidance, MATS documentation, and the AQMTSD.

We are using the base period 2003–2007 ambient ozone design value data for projecting future year design values. The ozone projection procedure is relatively simple, since ozone is a single species. It is not necessary to interpolate ambient ozone data, since ambient ozone design values and gridded, modeled ozone is all that is needed for the projections.

To project 8-hour ozone design values we used the 2005 base year and 2012 future base case model-predicted ozone concentrations to calculate relative response factors. The methodology we followed is consistent with the attainment demonstration modeling guidance. The RRFs were applied to the 2003–2007 ozone design values through the following steps:

Step 1: For each monitoring site we calculate the average concentration across all days with 8-hour daily maximum predictions greater than or equal to 85 ppb [46] using the predictions in the nine grid cells that include or surround the location of the monitoring site. The RRF for a site is the ratio of the mean prediction in the future year to the mean prediction in the 2005 base year. The RRFs were calculated on a site-by-site basis.

Step 2: The RRF for each site is then multiplied by the 2003–2007 5-year weighted average ambient design value for that site, yielding an estimate of the future year design value at that particular monitoring location.

Step 3: We calculate the maximum future design value by projecting design values for each of the three base periods (2003–2005, 2004–2006, and 2005–2007) separately. The highest of the three future values is the maximum design value. This maximum value is used to identify the 8-hour ozone maintenance receptors.

The preceding procedures for determining future year 8-hour average ozone design values were applied for each ozone monitoring site. The future year design values are truncated to integers in units of ppb. This approach is consistent with the truncation and rounding procedures for the 8-hour ozone NAAQS. Future year design values that are greater than or equal to 85 ppb are considered to be violating the NAAQS. Sites with future year 5-year weighted average design values of 85 ppb or greater are predicted to be nonattainment. Sites with future year maximum design values of 85 ppb or greater are predicted to be future year maintenance sites. Note that, as described previously for the annual and 24-hour $PM_{2.5}$ NAAQS, nonattainment sites for the ozone NAAQS are also maintenance sites because the maximum design value is always greater than or equal to the 5-year weighted average. For ease of reference we use the term "nonattainment sites" to refer to those sites that are projected to exceed the NAAQS based on both the average and maximum design values. Those sites that are projected to be attainment based on the average design value but exceed the NAAQS based on the maximum design value are referred to as maintenance sites. The monitoring sites that we project to be nonattainment and/or maintenance for the ozone NAAQS in the 2012 base case are the nonattainment/maintenance receptors used for assessing the contribution of emissions in upwind states to downwind nonattainment and maintenance of ozone NAAQS as part of this proposal.

Table IV.C–11 contains the 2003–2007 base period average and maximum 8-hour ozone design values and the 2012 base case average and maximum design values for sites projected to be 2012 nonattainment of the 8-hour ozone NAAQS in 2012. Table IV.C–12 contains this same information for projected 2012 8-hour ozone maintenance sites.

TABLE IV.C–11—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 8-HOUR OZONE DESIGN VALUES (PPB) AT PROJECTED NONATTAINMENT SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
220330003	Louisiana	East Baton Rouge	92	96	87.8	91.6
361030002	New York	Suffolk	90	91	86.3	87.2
361030009	New York	Suffolk	90.3	91	85.1	85.8
421010024	Pennsylvania	Philadelphia	90.3	91	85.3	86
480391004	Texas	Brazoria	94.7	97	88.8	91
482010051	Texas	Harris	93	98	88.4	93.1
482010055	Texas	Harris	100.7	103	95.7	97.9
482010062	Texas	Harris	95.7	99	90.5	93.7
482010066	Texas	Harris	92.3	96	89.9	93.5
482011039	Texas	Harris	96.3	100	90.5	93.9
484391002	Texas	Tarrant	93.3	95	85.1	86.7

TABLE IV.C–12—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 8-HOUR OZONE DESIGN VALUES (PPB) AT PROJECTED MAINTENANCE-ONLY SITES

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
90010017	Connecticut	Fairfield	88	90	83.1	85
90011123	Connecticut	Fairfield	92.3	94	84.8	86.4
90013007	Connecticut	Fairfield	90	92	84.5	86.4

[46] As specified in the attainment demonstration modeling guidance, if there are less than 10 modeled days > 85 ppb, then the threshold is lowered in 1 ppb increments (to as low as 70 ppb) until there are 10 days. If there are less than 5 days > 70 ppb, then an RRF calculation is not completed for that site.

TABLE IV.C–12—AVERAGE AND MAXIMUM 2003–2007 AND 2012 BASE CASE 8-HOUR OZONE DESIGN VALUES (PPB) AT PROJECTED MAINTENANCE-ONLY SITES—Continued

Monitor ID	State	County	Average design value 2003–2007	Maximum design value 2003–2007	Average design value 2012	Maximum design value 2012
90093002	Connecticut	New Haven	90.3	93	82.9	85.4
130890002	Georgia	DeKalb	88.7	93	81.6	85.6
131210055	Georgia	Fulton	91.7	94	84.4	86.5
361192004	New York	Westchester	87.7	90	84.7	86.9
420170012	Pennsylvania	Bucks	88	92	81.8	85.6
481130069	Texas	Dallas	87	90	82.9	85.8
481130087	Texas	Dallas	87	88	84.6	85.6
482010024	Texas	Harris	88	92	83.3	87.1
482010029	Texas	Harris	91.7	93	84.4	85.6
482011015	Texas	Harris	89	96	83.7	90.3
482011035	Texas	Harris	86.3	95	82	90.3
482011050	Texas	Harris	89.3	92	83.9	86.5
484392003	Texas	Tarrant	93.7	95	84	85.2

3. How did EPA assess interstate contributions to nonattainment and maintenance?

This section documents the procedures used by EPA to quantify the impact of emissions in specific upwind states on air quality concentrations in projected downwind nonattainment and maintenance locations for annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and 8-hour ozone. These procedures are the first of the two-step approach for determining significant contribution, as described previously in section IV.A.3.

EPA used CAMx photochemical source apportionment modeling to quantify the impact of emissions in specific upwind states on projected downwind nonattainment and maintenance receptors for both $PM_{2.5}$ and 8-hour ozone. Details of the modeling techniques and post-processing procedures are described in this section.

CAMx employs enhanced source apportionment techniques which track the formation and transport of ozone and particulate matter from specific emissions sources and calculates the contribution of sources and precursors to ozone and $PM_{2.5}$ for individual receptor locations. The strength of the photochemical model source apportionment technique is that all modeled ozone and/or $PM_{2.5}$ mass at a given receptor location in the modeling domain is tracked back to specific sources of emissions and boundary conditions to fully characterize culpable sources. This type of emissions apportionment is useful to understand the types of sources or regions that are contributing to ozone and $PM_{2.5}$ estimated by the model.

Source apportionment is an alternative approach to zero-out modeling[47] and other methods to track pollutant formation in photochemical models. Source apportionment completely characterizes source contributions to model-estimated ozone and $PM_{2.5}$, which is not possible with an emissions sensitivity approach such as zero-out, since the change in emissions leads to changes in pollutant concentrations, meaning the sum of estimated ozone or $PM_{2.5}$ in all zero-out simulations may not exactly match the ozone or $PM_{2.5}$ estimated in the base model simulation. Photochemical model source apportionment has the additional advantage over emissions sensitivity-based approaches of being more computationally efficient. There is currently no technical evidence showing that one technique is clearly superior to the other for evaluating contributions to ozone and $PM_{2.5}$ from various emission sources. However, since source apportionment explicitly tracks the formation and transport of all ozone and $PM_{2.5}$ mass, it is particularly well suited for quantifying interstate contributions as part of this proposal. More details on the implementation of photochemical source apportionment in CAMx can be found in the CAMx user's guide. In the analysis performed for CAIR, EPA conducted zero-out modeling for $PM_{2.5}$, and both zero-out and source apportionment modeling for ozone. The CAIR modeling was conducted at 36 km resolution for $PM_{2.5}$ and 12 km resolution for ozone. In contrast, the analysis for the Transport Rule was performed at 12 km resolution for both ozone and $PM_{2.5}$. When choosing the modeling techniques to use for the Transport Rule, we carefully considered all of the pros and cons of each technique, including the lengthy model run times and large file sizes of the 12 km eastern U.S. modeling domain. Due to the scientific credibility of the source apportionment technique and significant time and resource savings compared to zero-out modeling, we chose to perform the modeled contribution analyses for $PM_{2.5}$ and ozone with photochemical source apportionment.

The EPA performed source apportionment modeling for both ozone and $PM_{2.5}$ for the 2012 base case emissions. In this modeling we tracked the ozone and $PM_{2.5}$ formed from emissions from sources in each upwind state in the 12 km modeling domain. The results were used to calculate the contributions of these upwind emissions to downwind nonattainment and maintenance receptors. The states EPA analyzed using source apportionment for ozone and for $PM_{2.5}$ are: Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Vermont, Virginia, West Virginia, Washington DC, and Wisconsin. There were also several other states that are only partially contained within the 12 km modeling domain (*i.e.*, Colorado, Montana, New Mexico, and Wyoming). However, EPA did not individually track the emissions

[47] Zero-out modeling is a technique in which all emissions are removed (*e.g.*, NO_X and VOC emissions from a particular state) in a model run and then compared to the results of a second model run in which the same emissions have not been removed. The difference between the two model runs represents sensitivity or contribution from the emissions that were removed.

or assess the contribution from emissions in these states.

In contrast to CAIR, all contributions to downwind nonattainment and maintenance receptors for the Transport Rule were calculated using a relative approach. This is similar to the approach used to calculate future year design values, as described in section IV.C.2.a. In CAIR we used absolute and relative metrics to examine air quality contributions. Although absolute contributions are useful for certain applications, there are advantages of examining the relative contributions for both ozone and $PM_{2.5}$. The main advantage of relative contributions is that they help to minimize biases introduced by model over-predictions and under-predictions. Also, the relative approach constrains the total contributions to the measurements of ozone and $PM_{2.5}$ species concentrations at each downwind receptor. Since model performance is variable across the domain, EPA judged the relative approach to be the most appropriate technique for the Transport Rule.

a. Annual and 24-Hour $PM_{2.5}$ Contribution Modeling Approach

EPA used the CAMx Particulate Source Apportionment Technique (PSAT) to calculate downwind $PM_{2.5}$ contributions to nonattainment and maintenance. The CAMx PSAT is capable of "tagging" (*i.e.*, tracking) source category emissions for certain PM species and precursor emissions. For this proposal, we ran PSAT to tag emissions of NO_X, SO_2, and primary $PM_{2.5}$ from the individual states listed previously. Due to small modeled concentrations of secondary organic aerosols (SOA), and the relatively large runtime penalty of the SOA PSAT mechanism, we chose not to track SOA. Through emissions pre-processing procedures, EPA tagged all of the anthropogenic NO_X, SO_2, and primary $PM_{2.5}$ emissions in each upwind state. Each state was a separate tag, and the tagged emissions followed state boundaries (not grid cells).

In the PSAT simulation NO_X emissions are tracked to particulate nitrate concentrations, SO_2 emissions are tracked to particulate sulfate concentrations, and primary particulates (organic carbon, elemental carbon, and other $PM_{2.5}$) are tracked as primary particulates. As described earlier in section IV.B., the nitrate and sulfate contributions were combined and used to evaluate interstate contributions of $PM_{2.5}$, as described in section IV.C.4, later.

We developed and applied several post-processing steps to transform the PSAT modeling outputs to $PM_{2.5}$ downwind contributions. The approach involved processing the PSAT model outputs using MATS along with other post-processing software to calculate the contribution of each upwind state to each downwind nonattainment and/or maintenance receptor. This process involved calculating a ratio which uses the PSAT-predicted absolute contribution for each species (*e.g.*, sulfate) coupled with the CAMx-predicted absolute 2012 base case concentration of the same species. The PSAT-derived ratios were then multiplied by the corresponding species component concentrations comprising the 2012 base case $PM_{2.5}$ design value. For calculating annual contributions, we included the PSAT data for each day of the modeled year. For 24-hour calculations, the contributions are based on the 10 percent highest of the days in each quarter, as predicted for each receptor in the 2012 base case. In the 24-hour calculations, only the upwind contribution to the highest quarter at each receptor was used (*i.e.*, highest quarter based on 2012 $PM_{2.5}$ mass). For both annual and 24-hour $PM_{2.5}$, the total $PM_{2.5}$ mass contribution was calculated by summing the contributions of sulfate, nitrate, ammonium, and particle bound water.[48] Details on the procedures for calculating the contribution metrics are provided in the AQMTSD.

b. 8-Hour Ozone Contribution Modeling Approach

EPA used the CAM_X Ozone Source Apportionment Technique (OSAT) in order to calculate downwind 8-hour ozone contributions to nonattainment and maintenance. OSAT tracks the formation of ozone from NO_X and VOC emissions. Through emissions pre-processing procedures, EPA tagged all of the NO_X and VOC emissions in each upwind state. A separate tag was created for each state, and the tagged emissions followed state boundaries (not grid cells).

All anthropogenic sources of NO_X and VOC were tracked in the OSAT simulation. Upwind NO_X and VOC emissions were tracked to downwind ozone concentrations. There are several post-processing steps needed to transform the raw model outputs to ozone downwind contributions. We developed and applied several post-processing steps to transform the OSAT modeling outputs to ozone contributions at downwind receptors. The approach for ozone was similar to the approach for $PM_{2.5}$ in that the OSAT model outputs were processed using MATS along with other post-processing software to calculate the contribution of each upwind state to each downwind nonattainment and/or maintenance receptor. This process involved calculating a ratio which uses the OSAT-predicted absolute contribution of ozone coupled with the CAMx-predicted absolute 2012 base case ozone concentration. The OSAT-derived ratios were then multiplied by the corresponding 2012 base case ozone design value. The contributions to each downwind receptor are averaged across all days with modeled 2012 base case concentrations greater than 85 ppb[49] (at the given receptor). Details on the procedures for calculating the contribution metrics are provided in the AQMTSD.

c. Use of Projected Nonattainment and Maintenance Contributions

The previous steps provide the details for calculating 8-hour ozone and annual and 24-hour $PM_{2.5}$ contributions to all downwind receptors. After the post-processing of the model results is complete, we then evaluate the contributions of each upwind state to nonattainment and maintenance receptors. The nonattainment receptors are those monitoring sites which are projected to exceed the NAAQS in the 2012 base case, based on 5-year weighted average design values. The maintenance receptors are those monitoring sites which are projected to exceed the NAAQS in the 2012 base case based on the highest design value period. The upwind ozone and $PM_{2.5}$ contributions from each state are calculated for each downwind receptor. Contributions to nonattainment and maintenance receptors are evaluated independently for each state to determine if they are above the 1 percent threshold criteria.

For each upwind state, the maximum contribution to nonattainment is calculated based on the single largest

[48] The water and ammonium contributions are calculated by MATS using the default assumptions that were used to calculate future year 2012 $PM_{2.5}$ concentrations. The ammonium contribution is calculated assuming that all particulate nitrate is in the form of ammonium nitrate and the ammonium associated with sulfate is based on the degree of neutralization of the base year ambient data. In this way, the ammonium contribution is attributed to sulfate and nitrate precursors, not ammonia emissions. The water concentration is calculated based on an empirical formula that uses sulfate, nitrate, and ammonium concentrations.

[49] Ozone contributions are averaged over a minimum of 5 days. If there are fewer than 5 days greater than 85 ppb at a receptor, then the 85 ppb criterion is lowered in 1 ppb increments until there are 5 days of data for use in the calculations. If there are fewer than 5 modeled days greater than 70 ppb at the receptor, then the receptor is not used in the contribution calculations.

contribution to a future year (2012) downwind nonattainment receptor. The maximum contribution to maintenance is calculated based on the single largest contribution to a future year (2012) downwind maintenance receptor. Since the contributions are calculated independently for each receptor, the upwind contribution to maintenance can sometimes be larger than the contribution to nonattainment, and vice versa. This also means that maximum contributions to nonattainment can be below the threshold while maximum contributions to maintenance may be at or above the threshold, or vice versa.

4. What are the estimated interstate contributions to annual $PM_{2.5}$, 24-Hour $PM_{2.5}$, and 8-Hour ozone nonattainment and maintenance?

a. Contributions to Annual and 24-Hour $PM_{2.5}$ Nonattainment and Maintenance

In this section, we present the interstate contributions from emissions in upwind states to downwind nonattainment and maintenance sites for the annual $PM_{2.5}$ NAAQS. We also present the interstate contributions from emissions in upwind states to downwind nonattainment and maintenance sites for the 24-hour $PM_{2.5}$ NAAQS. As described previously in section IV.B., states which contribute 0.15 μg/m^{3}or more to annual $PM_{2.5}$ nonattainment or maintenance in another state are identified as states with contributions to downwind attainment and maintenance sites large enough to warrant further analysis. For 24-hour $PM_{2.5}$, states which contribute 0.35 μg/m^3 or more to 24-hour $PM_{2.5}$ nonattainment or maintenance in another state are identified as states with contributions to downwind attainment and maintenance sites large enough to warrant further analysis. As described previously in section IV.C.3, we performed air quality modeling to quantify the contributions to annual and 24-hour $PM_{2.5}$ from emissions in each of the following 37 states individually: Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland combined with the District of Columbia, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Vermont, Virginia, West Virginia, and Wisconsin.

For annual $PM_{2.5}$, we calculated each state's contribution to each of the 32 monitoring sites that are projected to be nonattainment and each of the 16 sites that are projected to have maintenance problems for the annual $PM_{2.5}$ NAAQS in the 2012 base case. The largest contribution from each state to annual $PM_{2.5}$ nonattainment in downwind sites is provided in Table IV.C–13. The largest contribution from each state to annual $PM_{2.5}$ maintenance in downwind sites is also provided in Table IV.C–13. The contributions from each state to all projected 2012 nonattainment and maintenance sites for the annual $PM_{2.5}$ NAAQS are provided in the AQMTSD.

TABLE IV.C–13—LARGEST CONTRIBUTION TO DOWNWIND ANNUAL $PM_{2.5}$ (μG/M^3) NONATTAINMENT AND MAINTENANCE FOR EACH OF 37 STATES

Upwind state	Largest downwind contribution to nonattainment for annual $PM_{2.5}$ (μg/m^3)	Largest downwind contribution to maintenance for annual $PM_{2.5}$ (μg/m^3)
Alabama	0.46	0.18
Arkansas	0.09	0.04
Connecticut	0.04	0.09
Delaware	0.20	0.14
Florida	0.29	0.07
Georgia	0.63	0.18
Illinois	1.01	0.63
Indiana	2.09	1.78
Iowa	0.31	0.30
Kansas	0.09	0.05
Kentucky	1.68	1.01
Louisiana	0.11	0.34
Maine	0.01	0.02
Maryland/Washington, D.C.	0.63	0.56
Massachusetts	0.07	0.13
Michigan	0.72	0.71
Minnesota	0.19	0.17
Mississippi	0.07	0.03
Missouri	1.38	0.27
Nebraska	0.08	0.06
New Hampshire	0.01	0.02
New Jersey	0.34	0.68
New York	0.49	0.47
North Carolina	0.19	0.11
North Dakota	0.05	0.05
Ohio	1.49	2.03
Oklahoma	0.08	0.05
Pennsylvania	0.83	1.60
Rhode Island	0.01	0.01
South Carolina	0.26	0.04
South Dakota	0.02	0.02
Tennessee	0.68	0.64
Texas	0.13	0.06
Vermont	0.00	0.00
Virginia	0.36	0.37

TABLE IV.C–13—LARGEST CONTRIBUTION TO DOWNWIND ANNUAL $PM_{2.5}$ (µG/M³) NONATTAINMENT AND MAINTENANCE FOR EACH OF 37 STATES—Continued

Upwind state	Largest downwind contribution to nonattainment for annual $PM_{2.5}$ (µg/m³)	Largest downwind contribution to maintenance for annual $PM_{2.5}$ (µg/m³)
West Virginia	0.98	1.17
Wisconsin	0.46	0.42

Based on the state-by-state contribution analysis, there are 22 states and the District of Columbia [50] which contribute 0.15 µg/m³ or more to downwind annual $PM_{2.5}$ nonattainment. These states are: Alabama, Delaware, the District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Minnesota, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin. In Table IV.C–14, we provide a list of the downwind nonattainment sites to which each upwind state contributes 0.15 µg/m³ or more (i.e., the upwind state to downwind nonattainment "linkages").

There are 19 states and the District of Columbia [51] which contribute 0.15 µg/m³ or more to downwind annual $PM_{2.5}$ maintenance. These states are: Alabama, the District of Columbia, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Missouri, New Jersey, New York, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin. In Table IV.C–15, we provide a list of the downwind maintenance sites to which each upwind state contributes 0.15 µg/m³ or more (i.e., the upwind state to downwind maintenance "linkages").

[50] EPA combined Maryland and the District of Columbia as a single entity in our contribution modeling. This is a logical approach because of the small size of the District of Columbia and, hence, its emissions and its close proximity to Maryland.

[51] As noted above, we combined Maryland and the District of Columbia as a single entity in our contribution modeling. This is a logical approach because of the small size of the District of Columbia and, hence, its emissions and its close proximity to Maryland.

TABLE IV.C–14—UPWIND STATE TO DOWNWIND NONATTAINMENT SITE "LINKAGES" FOR ANNUAL $PM_{2.5}$

Upwind State	Number of linkages	Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)						
Alabama	6	Bibb, GA (130210007)	Clayton, GA (130630091)	Fulton, GA (131210039)	Clark, IN (180190006)	Dubois, IN (180372001)	Jefferson, KY (211110043)	
Delaware	2	Lancaster, PA (420710007)	York, PA (421330008)					
Florida	3	Jefferson, AL (10730023)	Bibb, GA (130210007)	Clayton, GA (130630091)				
Georgia	7	Jefferson, AL (10730023)	Jefferson, AL (10732003)	Clark, IN (180190006)	Dubois, IN (180372001)	Jefferson, KY (211110043)	Kanawha, WV (540391005)	Cabell, WV (540110006)
Illinois	29	Jefferson, AL (10730023)	Jefferson, AL (10732003)	Fulton, GA (131210039)	Bibb, GA (130210007)	Clayton, GA (130630091)	Clark, IN (180190006)	Dubois, IN (180372001)
		Marion, IN (180970078)	Marion, IN (180970081)	Marion, IN (180970083)	Jefferson, KY (211110043)	Wayne, MI (261630015)	Wayne, MI (261630033)	Butler, OH (390170016)
		Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Hamilton, OH (390610014)	Hamilton, OH (390610042)	Hamilton, OH (390610043)	Hamilton, OH (390617001)
		Hamilton, OH (390618001)	Allegheny, PA (420030064)	Allegheny, PA (420031301)	Beaver, PA (420070014)	Lancaster, PA (420710007)	York, PA (421330008)	Cabell, WV (540110006)
		Kanawha, WV (540391005)						
Indiana	27	Jefferson, AL (10730023)	Jefferson, AL (10732003)	Bibb, GA (130210007)	Clayton, GA (130630091)	Fulton, GA (131210039)	Cook, IL (170310052)	Madison, IL (171191007)
		Saint Clair, IL (171630010)	Jefferson, KY (211110043)	Wayne, MI (261630015)	Wayne, MI (261630033)	Butler, OH (390170016)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)
		Cuyahoga, OH (390350060)	Hamilton, OH (390618001)	Hamilton, OH (390610014)	Hamilton, OH (390610042)	Hamilton, OH (390610043)	Hamilton, OH (390617001)	Allegheny, PA (420030064)
		Allegheny, PA (420031301)	Beaver, PA (420070014)	Lancaster, PA (420710007)	York, PA (421330008)	Cabell, WV (540110006)	Kanawha, WV (540391005)	
Iowa	4	Cook, IL (170310052)	Madison, IL (171191007)	Saint Clair, IL (171630010)	Dubois, IN (180372001)			
Kentucky	31	Jefferson, AL (10730023)	Jefferson, AL (10732003)	Bibb, GA (130210007)	Clayton, GA (130630091)	Fulton, GA (131210039)	Cook, IL (170310052)	Madison, IL (171191007)
		Saint Clair, IL (171630010)	Clark, IN (180190006)	Dubois, IN (180372001)	Marion, IN (180970078)	Marion, IN (180970081)	Marion, IN (180970083)	Wayne, MI (261630015)
		Wayne, MI (261630033)	Butler, OH (390170016)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Hamilton, OH (390610014)	Hamilton, OH (390610042)
		Hamilton, OH (390610043)	Hamilton, OH (390617001)	Hamilton, OH (390618001)	Allegheny, PA (420030064)	Allegheny, PA (420031301)	Beaver, PA (420070014)	Lancaster, PA (420710007)
		York, PA (421330008)	Cabell, WV (540110006)	Kanawha, WV (540391005)				
Maryland	2	Lancaster, PA (420710007)	York, PA (421330008)					
Michigan	25	Cook, IL (170310052)	Madison, IL (171191007)	Saint Clair, IL (171630010)	Clark, IN (180190006)	Dubois, IN (180372001)	Marion, IN (180970078)	Marion, IN (180970081)
		Marion, IN (180970083)	Jefferson, KY (211110043)	Butler, OH (390170016)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Hamilton, OH (390610014)
		Hamilton, OH (390610042)	Hamilton, OH (390610043)	Hamilton, OH (390617001)	Hamilton, OH (390618001)	Allegheny, PA (420030064)	Allegheny, PA (420031301)	Beaver, PA (420070014)
		Lancaster, PA (420710007)	York, PA (421330008)	Cabell, WV (540110006)	Kanawha, WV (540391005)			
Minnesota	1	Cook, IL (170310052)						
Missouri	17	Cook, IL (170310052)	Madison, IL (171191007)	Saint Clair, IL (171630010)	Clark, IN (180190006)	Dubois, IN (180372001)	Marion, IN (180970078)	Marion, IN (180970081)
		Marion, IN (180970083)	Jefferson, KY (211110043)	Butler, OH (390170016)	Hamilton, OH (390610014)	Hamilton, OH (390610042)	Hamilton, OH (390610043)	Hamilton, OH (390617001)
		Hamilton, OH (390618001)	Cabell, WV (540110006)	Kanawha, WV (540391005)				
New Jersey	2	Lancaster, PA (420710007)	York, PA (421330008)					

TABLE IV.C–14—UPWIND STATE TO DOWNWIND NONATTAINMENT SITE "LINKAGES" FOR ANNUAL $PM_{2.5}$—Continued

Upwind State	Number of linkages	Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)						
New York	8	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Allegheny, PA (420030064)	Allegheny, PA (420031301)	Beaver, PA (420070014)	Lancaster, PA (420710007)
		York, PA (421330008)						
North Carolina	3	Bibb, GA (130210007)	Clayton, GA (130630091)	Fulton, GA (131210039)				
Ohio	23	Jefferson, AL (10730023)	Jefferson, AL (10732003)	Bibb, GA (130210007)	Clayton, GA (130630091)	Fulton, GA (131210039)	Cook, IL (170310052)	Madison, IL (171191007)
		Saint Clair, IL (171630010)	Clark, IN (180190006)	Dubois, IN (180372001)	Marion, IN (180970078)	Marion, IN (180970081)	Marion, IN (180970083)	Jefferson, KY (211110043)
		Wayne, MI (261630015)	Wayne, MI (261630033)	Allegheny, PA (420030064)	Allegheny, PA (420031301)	Beaver, PA (420070014)	Lancaster, PA (420710007)	York, PA (421330008)
		Cabell, WV (540110006)	Kanawha, WV (540391005)					
Pennsylvania	25	Bibb, GA (130210007)	Clayton, GA (130630091)	Fulton, GA (131210039)	Cook, IL (170310052)	Madison, IL (171191007)	Saint Clair, IL (171630010)	Clark, IN (180190006)
		Dubois, IN (180372001)	Marion, IN (180970078)	Marion, IN (180970081)	Marion, IN (180970083)	Jefferson, KY (211110043)	Wayne, MI (261630015)	Wayne, MI (261630033)
		Butler, OH (390170016)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Hamilton, OH (390610014)	Hamilton, OH (390610042)	Hamilton, OH (390610043)
		Hamilton, OH (390617001)	Hamilton, OH (390618001)	Cabell, WV (540110006)	Kanawha, WV (540391005)			
South Carolina	3	Bibb, GA (130210007)	Clayton, GA (130630091)	Fulton, GA (131210039)				
Tennessee	29	Jefferson, AL (10730023)	Jefferson, AL (10732003)	Bibb, GA (130210007)	Clayton, GA (130630091)	Fulton, GA (131210039)	Clark, IN (180190006)	Madison, IL (171191007)
		Saint Clair, IL (171630010)	Dubois, IN (180372001)	Marion, IN (180970078)	Marion, IN (180970081)	Marion, IN (180970083)	Jefferson, KY (211110043)	Wayne, MI (261630015)
		Wayne, MI (261630033)	Butler, OH (390170016)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Hamilton, OH (390610014)	Hamilton, OH (390610042)
		Hamilton, OH (390610043)	Hamilton, OH (390617001)	Hamilton, OH (390618001)	Allegheny, PA (420030064)	Allegheny, PA (420031301)	Beaver, PA (420070014)	Cabell, WV (540110006)
		Kanawha, WV (540391005)						
Virginia	4	Lancaster, PA (420710007)	York, PA (421330008)	Cabell, WV (540110006)	Kanawha, WV (540391005)			
West Virginia	25	Fulton, GA (131210039)	Bibb, GA (130210007)	Clayton, GA (130630091)	Clark, IN (180190006)	Marion, IN (180970078)	Marion, IN (180970081)	Marion, IN (180970083)
		Dubois, IN (180372001)	Jefferson, KY (211110043)	Wayne, MI (261630015)	Wayne, MI (261630033)	Butler, OH (390170016)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)
		Cuyahoga, OH (390350060)	Hamilton, OH (390610014)	Hamilton, OH (390610042)	Hamilton, OH (390610043)	Hamilton, OH (390617001)	Hamilton, OH (390618001)	Allegheny, PA (420030064)
		Allegheny, PA (420031301)	Beaver, PA (420070014)	Lancaster, PA (420710007)	York, PA (421330008)			
Wisconsin	8	Cook, IL (170310052)	Dubois, IN (180372001)	Marion, IN (180970078)	Marion, IN (180970081)	Marion, IN (180970083)	Wayne, MI (261630015)	Wayne, MI (261630033)
		Cuyahoga, OH (390350045)						

TABLE IV.C–15—UPWIND STATE TO DOWNWIND MAINTENANCE SITE "LINKAGES" FOR ANNUAL $PM_{2.5}$

Upwind State	Number of linkages	Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)						
Alabama	1	Jefferson, KY (211110044)						
Georgia	1	Jefferson, KY (211110044)						
Illinois	13	Jefferson, KY (211110044)	Cuyahoga, OH (390350027)	Cuyahoga, OH (390350065)	Hamilton, OH (390610040)	Jefferson, OH (390811001)	Montgomery, OH (391130032)	Stark, OH (391510017)
		Berks, PA (420110011)	Harris, TX (482011035)	Berkeley, WV (540030003)	Brooke, WV (540090005)	Hancock, WV (540291004)	Marion, WV (540490006)	
Indiana	16	Cook, IL (170313301)	Cook, IL (170316005)	Jefferson, KY (211110044)	New York, NY (360610056)	Cuyahoga, OH (390350027)	Cuyahoga, OH (390350065)	Hamilton, OH (390610040)
		Jefferson, OH (390811001)	Montgomery, OH (391130032)	Stark, OH (391510017)	Berks, PA (420110011)	Harris, TX (482011035)	Berkeley, WV (540030003)	Brooke, WV (540090005)
		Hancock, WV (540291004)	Marion, WV (540490006)					
Iowa	2	Cook, IL (170313301)	Cook, IL (170316005)					
Kentucky	12	Cook, IL (170313301)	Cook, IL (170316005)	Cuyahoga, OH (390350027)	Cuyahoga, OH (390350065)	Hamilton, OH (390610040)	Jefferson, OH (390811001)	Montgomery, OH (391130032)
		Stark, OH (391510017)	Berkeley, WV (540030003)	Brooke, WV (540090005)	Hancock, WV (540291004)	Marion, WV (540490006)		
Louisiana	1	Harris, TX (482011035)						
Maryland	2	Berks, PA (420110011)	Berkeley, WV (540030003)					
Michigan	15	Cook, IL (170313301)	Cook, IL (170316005)	Jefferson, KY (211110044)	New York, NY (360610056)	Cuyahoga, OH (390350027)	Cuyahoga, OH (390350065)	Hamilton, OH (390610040)
		Jefferson, OH (390811001)	Montgomery, OH (391130032)	Stark, OH (391510017)	Berks, PA (420110011)	Berkeley, WV (540030003)	Brooke, WV (540090005)	Hancock, WV (540291004)
		Marion, WV (540490006)						
Minnesota	1	Cook, IL (170316005)						
Missouri	6	Cook, IL (170313301)	Cook, IL (170316005)	Jefferson, KY (211110044)	Hamilton, OH (390610040)	Montgomery, OH (391130032)	Stark, OH (391510017)	
New Jersey	2	New York, NY (360610056)	Berks, PA (420110011)					
New York	9	Cuyahoga, OH (390350027)	Cuyahoga, OH (390350065)	Jefferson, OH (390811001)	Stark, OH (391510017)	Berks, PA (420110011)	Berkeley, WV (540030003)	Brooke, WV (540090005)
		Hancock, WV (540291004)	Marion, WV (540490006)					
Ohio	9	Cook, IL (170313301)	Cook, IL (170316005)	Jefferson, KY (211110044)	New York, NY (360610056)	Berks, PA (420110011)	Berkeley, WV (540030003)	Brooke, WV (540090005)
		Hancock, WV (540291004)	Marion, WV (540490006)					
Pennsylvania	14	Cook, IL (170313301)	Cook, IL (170316005)	Jefferson, KY (211110044)	New York, NY (360610056)	Cuyahoga, OH (390350027)	Cuyahoga, OH (390350065)	Hamilton, OH (390610040)
		Jefferson, OH (390811001)	Montgomery, OH (391130032)	Stark, OH (391510017)	Berkeley, WV (540030003)	Brooke, WV (540090005)	Hancock, WV (540291004)	Marion, WV (540490006)
Tennessee	10	Jefferson, KY (211110044)	Cuyahoga, OH (390350027)	Cuyahoga, OH (390350065)	Hamilton, OH (390610040)	Jefferson, OH (390811001)	Montgomery, OH (391130032)	Stark, OH (391510017)
		Brooke, WV (540090005)	Hancock, WV (540291004)	Marion, WV (540490006)				
Virginia	4	New York, NY (360610056)	Berks, PA (420110011)	Berkeley, WV (540030003)	Marion, WV (540490006)			
West Virginia	9	Jefferson, KY (211110044)	New York, NY (360610056)	Cuyahoga, OH (390350027)	Cuyahoga, OH (390350065)	Hamilton, OH (390610040)	Jefferson, OH (390811001)	Montgomery, OH (391130032)
		Stark, OH (391510017)	Berks, PA (420110011)					

TABLE IV.C–15—UPWIND STATE TO DOWNWIND MAINTENANCE SITE "LINKAGES" FOR ANNUAL $PM_{2.5}$—Continued

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
Wisconsin	2	Cook, IL (170313301)	Cook, IL (170316005)				

For 24-hour $PM_{2.5}$, we calculated each state's contribution to each of the 92 monitoring sites that are projected to be nonattainment and each of the 38 sites that are projected to have maintenance problems for the 24-hour $PM_{2.5}$ NAAQS in the 2012 base case. The largest contribution from each state to 24-hour $PM_{2.5}$ nonattainment in downwind sites is provided in Table IV.C–16. The largest contribution from each state to 24-hour $PM_{2.5}$ maintenance in downwind sites is also provided in Table IV.C–16. The contributions from each state to all projected 2012 nonattainment and maintenance sites for the 24-hour $PM_{2.5}$ NAAQS are provided in the AQMTSD.

TABLE IV.C–16—LARGEST CONTRIBUTION TO DOWNWIND 24-HOUR $PM_{2.5}$ ($\mu g/m^3$) NONATTAINMENT AND MAINTENANCE FOR EACH OF 37 STATES

Upwind State	Largest downwind contribution to nonattainment for 24-hour $PM_{2.5}$ ($\mu g/m^3$)	Largest downwind contribution to maintenance for 24-hour $PM_{2.5}$ ($\mu g/m^3$)
Alabama	0.48	0.32
Arkansas	0.20	0.17
Connecticut	0.41	0.70
Delaware	0.50	0.36
Florida	0.08	0.08
Georgia	0.95	0.41
Illinois	7.28	6.57
Indiana	9.91	8.94
Iowa	1.87	1.67
Kansas	0.77	0.45
Kentucky	6.53	6.91
Louisiana	0.23	0.18
Maine	0.19	0.19
Maryland/Washington, DC	2.63	1.82
Massachusetts	0.67	0.71
Michigan	2.35	3.35
Minnesota	0.91	0.86
Mississippi	0.09	0.04
Missouri	5.03	4.82
Nebraska	0.62	0.39
New Hampshire	0.21	0.23
New Jersey	2.69	4.74
New York	5.82	1.17
North Carolina	0.50	0.45
North Dakota	0.27	0.15
Ohio	5.84	5.56
Oklahoma	0.16	0.21
Pennsylvania	3.67	4.86
Rhode Island	0.05	0.06
South Carolina	0.19	0.19
South Dakota	0.13	0.09
Tennessee	3.92	4.70
Texas	0.21	0.28
Vermont	0.06	0.07
Virginia	1.32	2.26
West Virginia	3.51	4.83
Wisconsin	0.80	1.01

Based on the state-by-state contribution analysis, there are 24 states and the District of Columbia [52] which contribute 0.35 $\mu g/m^3$ or more to downwind 24-hour $PM_{2.5}$ nonattainment. These states are: Alabama, the District of Columbia, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin. In Table IV.C–17, we provide a list of the downwind nonattainment counties to which each upwind state contributes 0.35 $\mu g/m^3$ or more (*i.e.*, the upwind state to downwind nonattainment "linkages").

There are 23 states and the District of Columbia which contribute 0.35 $\mu g/m^3$ or more to downwind 24-hour $PM_{2.5}$ maintenance. These states are: Connecticut, Delaware, the District of Columbia, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin. In Table IV.C–18, we provide a list of the downwind maintenance sites to which each upwind state contributes 0.35 $\mu g/m^3$ or more (*i.e.*, the upwind state to downwind maintenance "linkages").

[52] As noted above, we combined Maryland and the District of Columbia as a single entity in our contribution modeling. This is a logical approach because of the small size of the District of Columbia and, hence, its emissions and its close proximity to Maryland.

TABLE IV.C–17—UPWIND STATE TO DOWNWIND NONATTAINMENT SITE “LINKAGES” FOR 24-HOUR $PM_{2.5}$

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
Alabama	5	Monroe, MI (261150005)	Wayne, MI (261630015)	Hamilton, OH (390610006)	Hamilton, OH (390610014)	Hamilton, OH (390618001)	
Connecticut	3	Hudson, NJ (340172002)	New York, NY (360610056)	New York, NY (360610128)			
Delaware	2	Union, NJ (340390004)	Dauphin, PA (420430401)				
Georgia	12	Jefferson, AL (10730023)	Jefferson, AL (10732003)	Baltimore City, MD (245100040)	Baltimore City, MD (245100049)	Union, NJ (340390004)	Butler, OH (390170016)
		Butler, OH (390171004)	Hamilton, OH (390610006)	Hamilton, OH (390610014)	Hamilton, OH (390618001)	Montgomery, OH (391130032)	York, PA (421330008)
Illinois	70	Jefferson, AL (10730023)	Jefferson, AL (10732003)	New Haven, CT (90091123)	Clark, IN (180190006)	Dubois, IN (180372001)	Knox, IN (180830004)
		Lake, IN (180890022)	Lake, IN (180890026)	Marion, IN (180970042)	Marion, IN (180970043)	Marion, IN (180970066)	Marion, IN (180970078)
		Marion, IN (180970079)	Marion, IN (180970081)	Marion, IN (180970083)	Tippecanoe, IN (181570008)	Scott, IA (191630019)	Daviess, KY (210590005)
		Jefferson, KY (211110043)	Jefferson, KY (211110044)	Jefferson, KY (211110048)	Monroe, MI (261150005)	Oakland, MI (261250001)	St. Clair, MI (261470005)
		Washtenaw, MI (261610008)	Wayne, MI (261630015)	Wayne, MI (261630016)	Wayne, MI (261630019)	Wayne, MI (261630033)	Wayne, MI (261630036)
		Jefferson, MO (290990012)	Saint Charles, MO (291831002)	St. Louis City, MO (295100007)	St. Louis City, MO (295100087)	Union, NJ (340390004)	New York, NY (360610128)
		Butler, OH (390170003)	Butler, OH (390170016)	Butler, OH (390170017)	Butler, OH (390171004)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)
		Cuyahoga, OH (390350060)	Cuyahoga, OH (390350065)	Franklin, OH (390490024)	Franklin, OH (390490025)	Hamilton, OH (390610006)	Hamilton, OH (390610014)
		Hamilton, OH (390610040)	Hamilton, OH (390610042)	Hamilton, OH (390610043)	Hamilton, OH (390617001)	Hamilton, OH (390618001)	Jefferson, OH (390811001)
		Montgomery, OH (391130032)	Summit, OH (391530017)	Allegheny, PA (420030064)	Allegheny, PA (420030093)	Allegheny, PA (420030116)	Allegheny, PA (420031008)
		Allegheny, PA (420031301)	Beaver, PA (420070014)	Berks, PA (420110011)	Cambria, PA (420210011)	Montgomery, TN (471251009)	Brooke, WV (540090011)
		Milwaukee, WI (550790010)	Milwaukee, WI (550790026)	Milwaukee, WI (550790043)	Milwaukee, WI (550790099)		
Indiana	75	Jefferson, AL (10730023)	Jefferson, AL (10732003)	New Haven, CT (90091123)	Cook, IL (170310052)	Cook, IL (170310057)	Cook, IL (170310076)
		Cook, IL (170311016)	Cook, IL (170312001)	Cook, IL (170313103)	Cook, IL (170313301)	Cook, IL (170316005)	Madison, IL (171190023)
		Madison, IL (171191007)	Madison, IL (171192009)	Madison, IL (171193007)	Scott, IA (191630019)	Daviess, KY (210590005)	Jefferson, KY (211110043)
		Jefferson, KY (211110044)	Jefferson, KY (211110048)	Monroe, MI (261150005)	Oakland, MI (261250001)	St. Clair, MI (261470005)	Washtenaw, MI (261610008)
		Wayne, MI (261630015)	Wayne, MI (261630016)	Wayne, MI (261630019)	Wayne, MI (261630033)	Wayne, MI (261630036)	Jefferson, MO (290990012)
		Saint Charles, MO (291831002)	St. Louis City, MO (295100007)	St. Louis City, MO (295100087)	Hudson, NJ (340171003)	Union, NJ (340390004)	Bronx, NY (360050080)
		New York, NY (360610056)	New York, NY (360610128)	Butler, OH (390170003)	Butler, OH (390170016)	Butler, OH (390170017)	Butler, OH (390171004)
		Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Cuyahoga, OH (390350065)	Franklin, OH (390490024)	Franklin, OH (390490025)
		Hamilton, OH (390610006)	Hamilton, OH (390610014)	Hamilton, OH (390610040)	Hamilton, OH (390610042)	Hamilton, OH (390610043)	Hamilton, OH (390617001)
		Hamilton, OH (390618001)	Jefferson, OH (390811001)	Montgomery, OH (391130032)	Summit, OH (391530017)	Allegheny, PA (420030008)	Allegheny, PA (420030064)
		Allegheny, PA (420030093)	Allegheny, PA (420030116)	Allegheny, PA (420031008)	Allegheny, PA (420031301)	Beaver, PA (420070014)	Berks, PA (420110011)
		Cambria, PA (420210011)	Dauphin, PA (420430401)	York, PA (421330008)	Montgomery, TN (471251009)	Brooke, WV (540090011)	Milwaukee, WI (550790010)
		Milwaukee, WI (550790026)	Milwaukee, WI (550790043)	Milwaukee, WI (550790099)			
Iowa	17	Cook, IL (170310052)	Cook, IL (170310057)	Cook, IL (170310076)	Cook, IL (170311016)	Cook, IL (170312001)	Cook, IL (170313103)
		Cook, IL (170313301)	Cook, IL (170316005)	Madison, IL (171191007)	Lake, IN (180890022)	Lake, IN (180890026)	Jefferson, MO (290990012)
		St. Louis City, MO (295100007)	Milwaukee, WI (550790010)	Milwaukee, WI (550790026)	Milwaukee, WI (550790043)	Milwaukee, WI (550790099)	
Kansas	3	Milwaukee, WI (550790010)	Milwaukee, WI (550790026)	Milwaukee, WI (550790099)			
Kentucky	81	Jefferson, AL (10730023)	Jefferson, AL (10732003)	New Haven, CT (90091123)	Cook, IL (170310052)	Cook, IL (170310057)	Cook, IL (170310076)
		Cook, IL (170311016)	Cook, IL (170312001)	Cook, IL (170313103)	Cook, IL (170313301)	Cook, IL (170316005)	Madison, IL (171190023)
		Madison, IL (171191007)	Madison, IL (171192009)	Madison, IL (171193007)	Clark, IN (180190006)	Dubois, IN (180372001)	Knox, IN (180830004)
		Lake, IN (180890026)	Marion, IN (180970042)	Marion, IN (180970043)	Marion, IN (180970066)	Marion, IN (180970078)	Marion, IN (180970079)
		Marion, IN (180970081)	Marion, IN (180970083)	Tippecanoe, IN (181570008)	Scott, IA (191630019)	Monroe, MI (261150005)	Oakland, MI (261250001)

TABLE IV.C–17—UPWIND STATE TO DOWNWIND NONATTAINMENT SITE "LINKAGES" FOR 24-HOUR $PM_{2.5}$—Continued

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
		St. Clair, MI (261470005)	Washtenaw, MI (261610008)	Wayne, MI (261630015)	Wayne, MI (261630016)	Wayne, MI (261630019)	Wayne, MI (261630033)
		Wayne, MI (261630036)	Jefferson, MO (290990012)	Saint Charles, MO (291831002)	St. Louis City, MO (295100007)	St. Louis City, MO (295100087)	Hudson, NJ (340171003)
		Union, NJ (340390004)	Bronx, NY (360050080)	New York, NY (360610128)	Butler, OH (390170003)	Butler, OH (390170016)	Butler, OH (390170017)
		Butler, OH (390171004)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Cuyahoga, OH (390350065)	Franklin, OH (390490024)
		Franklin, OH (390490025)	Hamilton, OH (390610006)	Hamilton, OH (390610014)	Hamilton, OH (390610040)	Hamilton, OH (390610042)	Hamilton, OH (390610043)
		Hamilton, OH (390617001)	Hamilton, OH (390618001)	Jefferson, OH (390811001)	Montgomery, OH (391130032)	Summit, OH (391530017)	Allegheny, PA (420030008)
		Allegheny, PA (420030064)	Allegheny, PA (420030093)	Allegheny, PA (420030116)	Allegheny, PA (420031008)	Allegheny, PA (420031301)	Beaver, PA (420070014)
		Berks, PA (420110011)	Cambria, PA (420210011)	York, PA (421330008)	Montgomery, TN (471251009)	Brooke, WV (540090011)	Milwaukee, WI (550790010)
		Milwaukee, WI (550790026)	Milwaukee, WI (550790043)	Milwaukee, WI (550790099)			
Maryland	11	New Haven, CT (90091123)	Hudson, NJ (340171003)	Hudson, NJ (340172002)	Union, NJ (340390004)	Bronx, NY (360050080)	New York, NY (360610056)
		New York, NY (360610128)	Berks, PA (420110011)	Dauphin, PA (420430401)	Lancaster, PA (420710007)	York, PA (421330008)	
Massachusetts	3	New Haven, CT (90091123)	New York, NY (360610056)	New York, NY (360610128)			
Michigan	48	Cook, IL (170310052)	Cook, IL (170310057)	Cook, IL (170310076)	Cook, IL (170311016)	Cook, IL (170312001)	Cook, IL (170313103)
		Cook, IL (170313301)	Cook, IL (170316005)	Madison, IL (171190023)	Madison, IL (171191007)	Madison, IL (171192009)	Madison, IL (171193007)
		Knox, IN (180830004)	Lake, IN (180890022)	Lake, IN (180890026)	Scott, IA (191630019)	Jefferson, MO (290990012)	Saint Charles, MO (291831002)
		St. Louis City, MO (295100007)	St. Louis City, MO (295100087)	New York, NY (360610128)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)
		Cuyahoga, OH (390350065)	Franklin, OH (390490024)	Franklin, OH (390490025)	Hamilton, OH (390610014)	Hamilton, OH (390617001)	Hamilton, OH (390618001)
		Jefferson, OH (390811001)	Montgomery, OH (391130032)	Summit, OH (391530017)	Allegheny, PA (420030008)	Allegheny, PA (420030064)	Allegheny, PA (420030093)
		Allegheny, PA (420030116)	Allegheny, PA (420031008)	Allegheny, PA (420031301)	Beaver, PA (420070014)	Cambria, PA (420210011)	Dauphin, PA (420430401)
		Montgomery, TN (471251009)	Brooke, WV (540090011)	Milwaukee, WI (550790010)	Milwaukee, WI (550790026)	Milwaukee, WI (550790043)	
		Milwaukee, WI (550790099)					
Minnesota	4	Milwaukee, WI (550790010)	Milwaukee, WI (550790026)	Milwaukee, WI (550790043)	Milwaukee, WI (550790099)		
Missouri	56	Cook, IL (170310052)	Cook, IL (170310057)	Cook, IL (170310076)	Cook, IL (170311016)	Cook, IL (170312001)	Cook, IL (170313103)
		Cook, IL (170313301)	Cook, IL (170316005)	Madison, IL (171190023)	Madison, IL (171191007)	Madison, IL (171192009)	Madison, IL (171193007)
		Clark, IN (180190006)	Dubois, IN (180372001)	Knox, IN (180830004)	Lake, IN (180890022)	Lake, IN (180890026)	Marion, IN (180970042)
		Marion, IN (180970043)	Marion, IN (180970066)	Marion, IN (180970078)	Marion, IN (180970079)	Marion, IN (180970081)	Marion, IN (180970083)
		Tippecanoe, IN (181570008)	Scott, IA (191630019)	Daviess, KY (210590005)	Jefferson, KY (211110043)	Jefferson, KY (211110044)	Jefferson, KY (211110048)
		Monroe, MI (261150005)	Oakland, MI (261250001)	Washtenaw, MI (261610008)	Wayne, MI (261630015)	Wayne, MI (261630033)	Wayne, MI (261630036)
		Butler, OH (390170003)	Butler, OH (390170016)	Butler, OH (390170017)	Butler, OH (390171004)	Franklin, OH (390490024)	Franklin, OH (390490025)
		Hamilton, OH (390610006)	Hamilton, OH (390610014)	Hamilton, OH (390610040)	Hamilton, OH (390610042)	Hamilton, OH (390610043)	Hamilton, OH (390617001)
		Hamilton, OH (390618001)	Montgomery, OH (391130032)	Allegheny, PA (420030116)	Montgomery, TN (471251009)	Milwaukee, WI (550790010)	Milwaukee, WI (550790026)
		Milwaukee, WI (550790043)	Milwaukee, WI (550790099)				
Nebraska	3	Milwaukee, WI (550790010)	Milwaukee, WI (550790026)	Milwaukee, WI (550790099)			
New Jersey	9	New Haven, CT (90091123)	Baltimore City, MD (245100049)	Bronx, NY (360050080)	New York, NY (360610056)	New York, NY (360610128)	Berks, PA (420110011)
		Dauphin, PA (420430401)	Lancaster, PA (420710007)	York, PA (421330008)			
New York	23	New Haven, CT (90091123)	Baltimore City, MD (245100040)	Baltimore City, MD (245100049)	St. Clair, MI (261470005)	Washtenaw, MI (261610008)	Wayne, MI (261630016)
		Wayne, MI (261630019)	Wayne, MI (261630033)	Wayne, MI (261630036)	Hudson, NJ (340171003)	Hudson, NJ (340172002)	Union, NJ (340390004)
		Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Cuyahoga, OH (390350065)	Franklin, OH (390490024)	Franklin, OH (390490025)
		Summit, OH (391530017)	Berks, PA (420110011)	Dauphin, PA (420430401)	Lancaster, PA (420710007)	York, PA (421330008)	

TABLE IV.C–17—UPWIND STATE TO DOWNWIND NONATTAINMENT SITE "LINKAGES" FOR 24-HOUR $PM_{2.5}$—Continued

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
North Carolina	11	Baltimore City, MD (245100040)	Baltimore City, MD (245100049)	Hudson, NJ (340171003)	Hudson, NJ (340172002)	Union, NJ (340390004)	Bronx, NY (360050080)
		New York, NY (360610056)	Berks, PA (420110011)	Dauphin, PA (420430401)	Lancaster, PA (420710007)	York, PA (421330008)	
Ohio	72	Jefferson, AL (10730023)	Jefferson, AL (10732003)	New Haven, CT (90091123)	Cook, IL (170310052)	Cook, IL (170310057)	Cook, IL (170310076)
		Cook, IL (170311016)	Cook, IL (170312001)	Cook, IL (170313103)	Cook, IL (170313301)	Cook, IL (170316005)	Madison, IL (171190023)
		Madison, IL (171191007)	Madison, IL (171192009)	Madison, IL (171193007)	Clark, IN (180190006)	Dubois, IN (180372001)	Knox, IN (180830004)
		Lake, IN (180890022)	Lake, IN (180890026)	Marion, IN (180970042)	Marion, IN (180970043)	Marion, IN (180970066)	Marion, IN (180970078)
		Marion, IN (180970079)	Marion, IN (180970081)	Marion, IN (180970083)	Tippecanoe, IN (181570008)	Scott, IA (191630019)	Daviess, KY (210590005)
		Jefferson, KY (211110043)	Jefferson, KY (211110044)	Jefferson, KY (211110048)	Baltimore City, MD (245100040)	Baltimore City, MD (245100049)	Monroe, MI (261150005)
		Oakland, MI (261250001)	St. Clair, MI (261470005)	Washtenaw, MI (261610008)	Wayne, MI (261630015)	Wayne, MI (261630016)	Wayne, MI (261630019)
		Wayne, MI (261630033)	Wayne, MI (261630036)	Jefferson, MO (290990012)	Saint Charles, MO (291831002)	St. Louis City, MO (295100007)	St. Louis City, MO (295100087)
		Hudson, NJ (340171003)	Hudson, NJ (340172002)	Union, NJ (340390004)	Bronx, NY (360050080)	New York, NY (360610056)	New York, NY (360610128)
		Allegheny, PA (420030008)	Allegheny, PA (420030064)	Allegheny, PA (420030093)	Allegheny, PA (420030116)	Allegheny, PA (420031008)	Allegheny, PA (420031301)
		Beaver, PA (420070014)	Berks, PA (420110011)	Cambria, PA (420210011)	Dauphin, PA (420430401)	Lancaster, PA (420710007)	York, PA (421330008)
		Montgomery, TN (471251009)	Brooke, WV (540090011)	Milwaukee, WI (550790010)	Milwaukee, WI (550790026)	Milwaukee, WI (550790043)	Milwaukee, WI (550790099)
Pennsylvania	77	Jefferson, AL (10730023)	Jefferson, AL (10732003)	New Haven, CT (90091123)	Cook, IL (170310052)	Cook, IL (170310057)	Cook, IL (170310076)
		Cook, IL (170311016)	Cook, IL (170312001)	Cook, IL (170313103)	Cook, IL (170313301)	Cook, IL (170316005)	Madison, IL (171191007)
		Madison, IL (171192009)	Madison, IL (171193007)	Madison, IL (171190023)	Clark, IN (180190006)	Dubois, IN (180372001)	Knox, IN (180830004)
		Lake, IN (180890026)	Marion, IN (180970042)	Marion, IN (180970043)	Marion, IN (180970066)	Marion, IN (180970078)	Marion, IN (180970079)
		Marion, IN (180970081)	Marion, IN (180970083)	Tippecanoe, IN (181570008)	Scott, IA (191630019)	Jefferson, KY (211110043)	Jefferson, KY (211110044)
		Jefferson, KY (211110048)	Baltimore City, MD (245100040)	Baltimore City, MD (245100049)	Monroe, MI (261150005)	Oakland, MI (261250001)	St. Clair, MI (261470005)
		Washtenaw, MI (261610008)	Wayne, MI (261630015)	Wayne, MI (261630016)	Wayne, MI (261630019)	Wayne, MI (261630033)	Wayne, MI (261630036)
		Jefferson, MO (290990012)	Saint Charles, MO (291831002)	St. Louis City, MO (295100007)	St. Louis City, MO (295100087)	Hudson, NJ (340171003)	Hudson, NJ (340172002)
		Union, NJ (340390004)	Bronx, NY (360050080)	New York, NY (360610056)	New York, NY (360610128)	Butler, OH (390170003)	Butler, OH (390170016)
		Butler, OH (390170017)	Butler, OH (390171004)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Cuyahoga, OH (390350065)
		Franklin, OH (390490024)	Franklin, OH (390490025)	Hamilton, OH (390610006)	Hamilton, OH (390610014)	Hamilton, OH (390610040)	Hamilton, OH (390610042)
		Hamilton, OH (390610043)	Hamilton, OH (390617001)	Hamilton, OH (390618001)	Jefferson, OH (390811001)	Montgomery, OH (391130032)	Summit, OH (391530017)
		Montgomery, TN (471251009)	Brooke, WV (540090011)	Milwaukee, WI (550790026)	Milwaukee, WI (550790043)	Milwaukee, WI (550790099)	
Tennessee	61	Jefferson, AL (10730023)	Jefferson, AL (10732003)	New Haven, CT (90091123)	Madison, IL (171190023)	Madison, IL (171191007)	Madison, IL (171192009)
		Madison, IL (171193007)	Clark, IN (180190006)	Dubois, IN (180372001)	Knox, IN (180830004)	Marion, IN (180970042)	Marion, IN (180970043)
		Marion, IN (180970066)	Marion, IN (180970078)	Marion, IN (180970079)	Marion, IN (180970081)	Marion, IN (180970083)	Tippecanoe, IN (181570008)
		Scott, IA (191630019)	Daviess, KY (210590005)	Jefferson, KY (211110043)	Jefferson, KY (211110044)	Jefferson, KY (211110048)	Monroe, MI (261150005)
		Oakland, MI (261250001)	St. Clair, MI (261470005)	Washtenaw, MI (261610008)	Wayne, MI (261630015)	Wayne, MI (261630033)	Wayne, MI (261630036)
		Jefferson, MO (290990012)	Saint Charles, MO (291831002)	St. Louis City, MO (295100007)	St. Louis City, MO (295100087)	Union, NJ (340390004)	New York, NY (360610128)
		Butler, OH (390170003)	Butler, OH (390170016)	Butler, OH (390170017)	Butler, OH (390171004)	Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)
		Cuyahoga, OH (390350065)	Franklin, OH (390490024)	Franklin, OH (390490025)	Hamilton, OH (390610006)	Hamilton, OH (390610014)	Hamilton, OH (390610040)
		Hamilton, OH (390610042)	Hamilton, OH (390610043)	Hamilton, OH (390617001)	Hamilton, OH (390618001)	Jefferson, OH (390811001)	Montgomery, OH (391130032)
		Summit, OH (391530017)	Allegheny, PA (420030093)	Allegheny, PA (420030116)	Allegheny, PA (420031008)	Allegheny, PA (420031301)	Cambria, PA (420210011)
		York, PA (421330008)					
Virginia	13	New Haven, CT (90091123)	Baltimore City, MD (245100040)	Baltimore City, MD (245100049)	Hudson, NJ (340171003)	Hudson, NJ (340172002)	Union, NJ (340390004)

TABLE IV.C–17—UPWIND STATE TO DOWNWIND NONATTAINMENT SITE "LINKAGES" FOR 24-HOUR $PM_{2.5}$—Continued

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
		Bronx, NY (360050080)	New York, NY (360610056)	New York, NY (360610128)	Berks, PA (420110011)	Dauphin, PA (420430401)	Lancaster, PA (420710007)
		York, PA (421330008)					
West Virginia	84	Jefferson, AL (10730023)	Jefferson, AL (10732003)	New Haven, CT (90091123)	Cook, IL (170310052)	Cook, IL (170310057)	Cook, IL (170310076)
		Cook, IL (170311016)	Cook, IL (170312001)	Cook, IL (170313301)	Cook, IL (170316005)	Madison, IL (171190023)	Madison, IL (171191007)
		Madison, IL (171192009)	Madison, IL (171193007)	Clark, IN (180190006)	Dubois, IN (180372001)	Lake, IN (180890026)	Marion, IN (180970042)
		Marion, IN (180970043)	Marion, IN (180970066)	Marion, IN (180970078)	Marion, IN (180970079)	Marion, IN (180970081)	Marion, IN (180970083)
		Tippecanoe, IN (181570008)	Scott, IA (191630019)	Jefferson, KY (211110043)	Jefferson, KY (211110044)	Jefferson, KY (211110048)	Baltimore City, MD (245100040)
		Baltimore City, MD (245100049)	Monroe, MI (261150005)	Oakland, MI (261250001)	St. Clair, MI (261470005)	Washtenaw, MI (261610008)	Wayne, MI (261630015)
		Wayne, MI (261630016)	Wayne, MI (261630019)	Wayne, MI (261630033)	Wayne, MI (261630036)	Jefferson, MO (290990012)	Saint Charles, MO (291831002)
		St. Louis City, MO (295100007)	St. Louis City, MO (295100087)	Hudson, NJ (340171003)	Hudson, NJ (340172002)	Union, NJ (340390004)	Bronx, NY (360050080)
		New York, NY (360610056)	New York, NY (360610128)	Butler, OH (390170003)	Butler, OH (390170016)	Butler, OH (390170017)	Butler, OH (390171004)
		Cuyahoga, OH (390350038)	Cuyahoga, OH (390350045)	Cuyahoga, OH (390350060)	Cuyahoga, OH (390350065)	Franklin, OH (390490024)	Franklin, OH (390490025)
		Hamilton, OH (390610006)	Hamilton, OH (390610014)	Hamilton, OH (390610040)	Hamilton, OH (390610042)	Hamilton, OH (390610043)	Hamilton, OH (390617001)
		Hamilton, OH (390618001)	Jefferson, OH (390811001)	Montgomery, OH (391130032)	Summit, OH (391530017)	Allegheny, PA (420030008)	Allegheny, PA (420030064)
		Allegheny, PA (420030093)	Allegheny, PA (420030116)	Allegheny, PA (420031008)	Allegheny, PA (420031301)	Beaver, PA (420070014)	Berks, PA (420110011)
		Cambria, PA (420210011)	Dauphin, PA (420430401)	Lancaster, PA (420710007)	York, PA (421330008)	Montgomery, TN (471251009)	Milwaukee, WI (550790043)
Wisconsin	12	Cook, IL (170310052)	Cook, IL (170310057)	Cook, IL (170310076)	Cook, IL (170311016)	Cook, IL (170312001)	Cook, IL (170313103)
		Cook, IL (170313301)	Cook, IL (170316005)	Lake, IN (180890022)	Lake, IN (180890026)	Scott, IA (191630019)	Wayne, MI (261630016)

TABLE IV.C–18—UPWIND STATE TO DOWNWIND MAINTENANCE SITE "LINKAGES" FOR 24-HOUR $PM_{2.5}$

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
Connecticut	1	New York, NY (360610062)					
Delaware	2	Cumberland, PA (420410101)	New York, NY (360610079)				
Georgia	3	Baltimore City, MD (245100035)	Lucas, OH (390950026)	Preble, OH (391351001)			
Illinois	29	District of Columbia (110010041)	District of Columbia (110010042)	Elkhart, IN (180390003)	Floyd, IN (180431004)	Vigo, IN (181670023)	Muscatine, IA (191390015)
		Bullitt, KY (210290006)	McCracken, KY (211451004)	Warren, KY (212270007)	Wayne, MI (261630001)	St. Louis City, MO (295100085)	New York, NY (360610079)
		Cuyahoga, OH (390350027)	Cuyahoga, OH (390350034)	Jefferson, OH (390810017)	Lucas, OH (390950024)	Lucas, OH (390950026)	Mahoning, OH (390990014)
		Montgomery, OH (391130031)	Preble, OH (391351001)	Trumbull, OH (391550007)	Allegheny, PA (420030095)	Allegheny, PA (420033007)	Washington, PA (421255001)
		Sumner, TN (471650007)	Brooke, WV (540090005)	Dane, WI (550250047)	Milwaukee, WI (550790059)	Waukesha, WI (551330027)	
Indiana	34	District of Columbia (110010041)	District of Columbia (110010042)	Cook, IL (170310022)	Cook, IL (170310050)	Cook, IL (170314007)	Saint Clair, IL (171630010)
		Will, IL (171971002)	Muscatine, IA (191390015)	Bullitt, KY (210290006)	McCracken, KY (211451004)	Warren, KY (212270007)	Anne Arundel, MD (240031003)
		Wayne, MI (261630001)	St. Louis City, MO (295100085)	New York, NY (360610062)	New York, NY (360610079)	Cuyahoga, OH (390350027)	Cuyahoga, OH (390350034)
		Jefferson, OH (390810017)	Lucas, OH (390950024)	Lucas, OH (390950026)	Mahoning, OH (390990014)	Montgomery, OH (391130031)	Preble, OH (391351001)
		Trumbull, OH (391550007)	Allegheny, PA (420030095)	Allegheny, PA (420033007)	Cumberland, PA (420410101)	Washington, PA (421255001)	Sumner, TN (471650007)
		Brooke, WV (540090005)	Dane, WI (550250047)	Milwaukee, WI (550790059)	Waukesha, WI (551330027)		
Iowa	9	Cook, IL (170310022)	Cook, IL (170310050)	Cook, IL (170314007)	Will, IL (171971002)	Elkhart, IN (180390003)	St. Louis City, MO (295100085)

TABLE IV.C–18—UPWIND STATE TO DOWNWIND MAINTENANCE SITE "LINKAGES" FOR 24-HOUR $PM_{2.5}$—Continued

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
		Dane, WI (550250047)	Milwaukee, WI (550790059)	Waukesha, WI (551330027)			
Kansas	2	Muscatine, IA (191390015)	Milwaukee, WI (550790059)				
Kentucky	33	District of Columbia (110010041)	District of Columbia (110010042)	Cook, IL (170310022)	Cook, IL (170310050)	Cook, IL (170314007)	Saint Clair, IL (171630010)
		Will, IL (171971002)	Elkhart, IN (180390003)	Floyd, IN (180431004)	Vigo, IN (181670023)	Muscatine, IA (191390015)	Anne Arundel, MD (240031003)
		Wayne, MI (261630001)	St. Louis City, MO (295100085)	New York, NY (360610062)	New York, NY (360610079)	Cuyahoga, OH (390350027)	Cuyahoga, OH (390350034)
		Jefferson, OH (390810017)	Lucas, OH (390950024)	Lucas, OH (390950026)	Mahoning, OH (390990014)	Montgomery, OH (391130031)	Preble, OH (391351001)
		Trumbull, OH (391550007)	Allegheny, PA (420030095)	Allegheny, PA (420033007)	Washington, PA (421255001)	Sumner, TN (471650007)	Brooke, WV (540090005)
		Dane, WI (550250047)	Milwaukee, WI (550790059)	Waukesha, WI (551330027)			
Maryland	5	District of Columbia (110010041)	District of Columbia (110010042)	New York, NY (360610062)	New York, NY (360610079)	Cumberland, PA (420410101)	
Massachusetts	1	New York, NY (360610062)					
Michigan	28	District of Columbia (110010041)	Cook, IL (170310022)	Cook, IL (170310050)	Cook, IL (170314007)	Saint Clair, IL (171630010)	Will, IL (171971002)
		Elkhart, IN (180390003)	Vigo, IN (181670023)	Muscatine, IA (191390015)	Warren, KY (212270007)	St. Louis City, MO (295100085)	Cuyahoga, OH (390350027)
		Cuyahoga, OH (390350034)	Jefferson, OH (390810017)	Lucas, OH (390950024)	Lucas, OH (390950026)	Mahoning, OH (390990014)	Montgomery, OH (391130031)
		Preble, OH (391351001)	Trumbull, OH (391550007)	Allegheny, PA (420030095)	Allegheny, PA (420033007)	Washington, PA (421255001)	Sumner, TN (471650007)
		Brooke, WV (540090005)	Dane, WI (550250047)	Milwaukee, WI (550790059)	Waukesha, WI (551330027)		
Minnesota	4	Muscatine, IA (191390015)	Dane, WI (550250047)	Milwaukee, WI (550790059)	Waukesha, WI (551330027)		
Missouri	20	Cook, IL (170310022)	Cook, IL (170310050)	Cook, IL (170314007)	Saint Clair, IL (171630010)	Will, IL (171971002)	Elkhart, IN (180390003)
		Floyd, IN (180431004)	Vigo, IN (181670023)	Muscatine, IA (191390015)	Bullitt, KY (210290006)	McCracken, KY (211451004)	Warren, KY (212270007)
		Jefferson, OH (390810017)	Lucas, OH (390950026)	Montgomery, OH (391130031)	Preble, OH (391351001)	Sumner, TN (471650007)	Dane, WI (550250047)
		Milwaukee, WI (550790059)	Waukesha, WI (551330027)				
Nebraska	2	Muscatine, IA (191390015)	Milwaukee, WI (550790059)				
New Jersey	5	District of Columbia (110010041)	Anne Arundel, MD (240031003)	New York, NY (360610062)	New York, NY (360610079)	Cumberland, PA (420410101)	
New York	9	District of Columbia (110010041)	District of Columbia (110010042)	Anne Arundel, MD (240031003)	Baltimore City, MD (245100035)	Cuyahoga, OH (390350027)	Cuyahoga, OH (390350034)
		Lucas, OH (390950024)	Lucas, OH (390950026)	Cumberland, PA (420410101)			
North Carolina	3	Baltimore City, MD (245100035)	New York, NY (360610062)	New York, NY (360610079)			
Ohio	29	District of Columbia (110010041)	District of Columbia (110010042)	Cook, IL (170310022)	Cook, IL (170310050)	Cook, IL (170314007)	Saint Clair, IL (171630010)
		Will, IL (171971002)	Elkhart, IN (180390003)	Floyd, IN (180431004)	Vigo, IN (181670023)	Muscatine, IA (191390015)	Bullitt, KY (210290006)
		McCracken, KY (211451004)	Warren, KY (212270007)	Anne Arundel, MD (240031003)	Baltimore City, MD (245100035)	Wayne, MI (261630001)	St. Louis City, MO (295100085)
		New York, NY (360610062)	New York, NY (360610079)	Allegheny, PA (420030095)	Allegheny, PA (420033007)	Cumberland, PA (420410101)	Washington, PA (421255001)
		Sumner, TN (471650007)	Brooke, WV (540090005)	Dane, WI (550250047)	Milwaukee, WI (550790059)	Waukesha, WI (551330027)	
Pennsylvania	32	District of Columbia (110010041)	District of Columbia (110010042)	Cook, IL (170310022)	Cook, IL (170310050)	Cook, IL (170314007)	Saint Clair, IL (171630010)
		Will, IL (171971002)	Elkhart, IN (180390003)	Floyd, IN (180431004)	Vigo, IN (181670023)	Muscatine, IA (191390015)	Bullitt, KY (210290006)
		Warren, KY (212270007)	Anne Arundel, MD (240031003)	Baltimore City, MD (245100035)	Wayne, MI (261630001)	New York, NY (360610062)	New York, NY (360610079)
		Cuyahoga, OH (390350027)	Cuyahoga, OH (390350034)	Jefferson, OH (390810017)	Lucas, OH (390950024)	Lucas, OH (390950026)	Mahoning, OH (390990014)
		Montgomery, OH (391130031)	Preble, OH (391351001)	Trumbull, OH (391550007)	Sumner, TN (471650007)	Brooke, WV (540090005)	Dane, WI (550250047)

TABLE IV.C–18—UPWIND STATE TO DOWNWIND MAINTENANCE SITE "LINKAGES" FOR 24-HOUR $PM_{2.5}$—Continued

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
		Milwaukee, WI (550790059)	Waukesha, WI (551330027)				
Tennessee	21	Cook, IL (170314007)	Saint Clair, IL (171630010)	Will, IL (171971002)	Elkhart, IN (180390003)	Floyd, IN (180431004)	Vigo, IN (181670023)
		Muscatine, IA (191390015)	Bullitt, KY (210290006)	McCracken, KY (211451004)	Warren, KY (212270007)	Wayne, MI (261630001)	St. Louis City, MO (295100085)
		Jefferson, OH (390810017)	Lucas, OH (390950024)	Lucas, OH (390950026)	Mahoning, OH (390990014)	Montgomery, OH (391130031)	Preble, OH (391351001)
		Trumbull, OH (391550007)	Allegheny, PA (420033007)	Washington, PA (421255001)			
Virginia	7	District of Columbia (110010041)	District of Columbia (110010042)	Anne Arundel, MD (240031003)	Baltimore City, MD (245100035)	New York, NY (360610062)	New York, NY (360610079)
		Cumberland, PA (420410101)					
West Virginia	35	District of Columbia (110010041)	District of Columbia (110010042)	Cook, IL (170310050)	Cook, IL (170314007)	Saint Clair, IL (171630010)	Will, IL (171971002)
		Elkhart, IN (180390003)	Floyd, IN (180431004)	Vigo, IN (181670023)	Muscatine, IA (191390015)	Bullitt, KY (210290006)	Warren, KY (212270007)
		Anne Arundel, MD (240031003)	Baltimore City, MD (245100035)	Wayne, MI (261630001)	St. Louis City, MO (295100085)	New York, NY (360610062)	New York, NY (360610079)
		Cuyahoga, OH (390350027)	Cuyahoga, OH (390350034)	Jefferson, OH (390810017)	Lucas, OH (390950024)	Lucas, OH (390950026)	Mahoning, OH (390990014)
		Montgomery, OH (391130031)	Preble, OH (391351001)	Trumbull, OH (391550007)	Allegheny, PA (420030095)	Allegheny, PA (420033007)	Cumberland, PA (420410101)
		Washington, PA (421255001)	Sumner, TN (471650007)	Dane, WI (550250047)	Milwaukee, WI (550790059)	Waukesha, WI (551330027)	
Wisconsin	6	Cook, IL (170310022)	Cook, IL (170310050)	Cook, IL (170314007)	Will, IL (171971002)	Elkhart, IN (180390003)	Muscatine, IA (191390015)

b. Results of 8-Hour Ozone Contribution Modeling

In this section, we present the interstate contributions from emissions in upwind states to downwind nonattainment and maintenance sites for the ozone NAAQS. As described previously in section IV.B., states which contribute 0.8 ppb or more to 8-hour ozone nonattainment or maintenance in another state are identified as states with contributions to downwind attainment and maintenance sites large enough to warrant further analysis. We performed air quality modeling to quantify the contributions to 8-hour ozone from emissions in each of the following 37 states individually: Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland combined with the District of Columbia, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Vermont, Virginia, West Virginia, and Wisconsin.

We calculated each state's contribution to each of the 11 monitoring sites that are projected to be nonattainment and each of 14 [53] sites that are projected to have maintenance problems for the 8-hour ozone NAAQS in the 2012 Base Case. The largest contribution from each state to 8-hour ozone nonattainment in downwind sites is provided in Table IV.C–19. The largest contribution from each state to 8-hour ozone maintenance in downwind sites is also provided in Table IV.C–19. The contributions from each state to all projected 2012 nonattainment and maintenance sites for the 8-hour ozone NAAQS are provided in the AQMTSD.

TABLE IV.C–19—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE FOR EACH OF 37 STATES

Upwind State	Largest downwind contribution to nonattainment for ozone (ppb)	Largest downwind contribution to maintenance for ozone (ppb)
Alabama	4.7	4.7
Arkansas	1.4	1.8
Connecticut	1.7	1.6
Delaware	3.3	2.5
Florida	0.8	2.1
Georgia	2.1	1.7

[53] For two of the 16 projected maintenance sites (Harris Co., Texas sites 482011015 and 482011035) there were less than 5 days with 8-hour ozone predictions of at least 70 ppb. Thus, we did not calculate contributions for these two maintenance sites.

TABLE IV.C–19—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE FOR EACH OF 37 STATES—Continued

Upwind State	Largest downwind contribution to nonattainment for ozone (ppb)	Largest downwind contribution to maintenance for ozone (ppb)
Illinois	0.8	0.6
Indiana	1.1	1.0
Iowa	0.3	0.3
Kansas	0.6	0.8
Kentucky	2.3	1.8
Louisiana	11.4	10.6
Maine	0.0	0.0
Maryland/Washington, DC	6.1	4.2
Massachusetts	0.6	0.5
Michigan	0.9	0.5
Minnesota	0.1	0.2
Mississippi	5.2	2.5
Missouri	0.7	0.6
Nebraska	0.2	0.2
New Hampshire	0.1	0.1
New Jersey	16.8	15.8
New York	0.4	22.7
North Carolina	1.7	2.0
North Dakota	0.1	0.0
Ohio	2.8	2.6
Oklahoma	2.1	2.7
Pennsylvania	8.9	8.1
Rhode Island	0.1	0.1
South Carolina	0.6	0.8
South Dakota	0.0	0.0
Tennessee	1.6	3.0
Texas	1.6	0.6
Vermont	0.0	0.1
Virginia	4.2	4.5
West Virginia	2.7	2.3
Wisconsin	0.3	0.2

Based on the state-by-state contribution analysis, there are 22 states and the District of Columbia[54] which contribute 0.8 ppb or more to downwind 8-hour ozone nonattainment. These states are: Alabama, Arkansas, Connecticut, Delaware, the District of Columbia, Florida, Georgia, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, New Jersey, North Carolina, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, and West Virginia. In Table IV.C–20, we provide a list of the downwind nonattainment counties to which each upwind state contributes 0.8 ppb or more (i.e., the upwind state to downwind nonattainment "linkages").

There are 22 states and the District of Columbia which contribute 0.8 ppb or more to downwind 8-hour ozone maintenance. These states are: Alabama, Arkansas, Connecticut, Delaware, the District of Columbia, Florida, Georgia, Indiana, Kansas, Kentucky, Louisiana, Maryland, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Virginia, and West Virginia. In Table IV.C–21, we provide a list of the downwind nonattainment counties to which each upwind state contributes 0.8 ppb or more (i.e., the upwind state to downwind nonattainment "linkages").

TABLE IV.C–20—UPWIND STATE TO DOWNWIND NONATTAINMENT "LINKAGES" FOR 8-HOUR OZONE

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
Alabama	8	East Baton Rouge, LA (220330003)	Brazoria, TX (480391004)	Harris, TX (482010051)	Harris, TX (482010055)	Harris, TX (482010062)	Harris, TX (482010066)
		Harris, TX (482011039)	Tarrant, TX (484391002)				
Arkansas	3	East Baton Rouge, LA (220330003)	Brazoria, TX (480391004)	Tarrant, TX (484391002)			

[54] As noted above, we combined Maryland and the District of Columbia as a single entity in our contribution modeling. This is a logical approach because of the small size of the District of Columbia and, hence, its emissions and its close proximity to Maryland. Under our analysis, Maryland and the District of Columbia are linked as significant contributors to the same downwind nonattainment counties.

TABLE IV.C–20—UPWIND STATE TO DOWNWIND NONATTAINMENT "LINKAGES" FOR 8-HOUR OZONE—Continued

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
Connecticut	1	Suffolk, NY (361030009)					
Delaware	3	Suffolk, NY (361030002)	Suffolk, NY (361030009)	Philadelphia, PA (421010024)			
Florida	2	Harris, TX (482010062)	Tarrant, TX (484391002)				
Georgia	7	Brazoria, TX (480391004)	Harris, TX (482010051)	Harris, TX (482010055)	Harris, TX (482010062)	Harris, TX (482010066)	Harris, TX (482011039)
		Tarrant, TX (484391002)					
Illinois	2	Suffolk, NY (361030009)	Harris, TX (482010055)				
Indiana	3	Suffolk, NY (361030002)	Suffolk, NY (361030009)	Philadelphia, PA (421010024)			
Kentucky	6	Suffolk, NY (361030002)	Philadelphia, PA (421010024)	Harris, TX (482010051)	Harris, TX (482010055)	Harris, TX (482010062)	Harris, TX (482011039)
Louisiana	7	Brazoria, TX (480391004)	Harris, TX (482010051)	Harris, TX (482010055)	Harris, TX (482010062)	Harris, TX (482010066)	Harris, TX (482011039)
		Tarrant, TX (484391002)					
Maryland	3	Suffolk, NY (361030002)	Suffolk, NY (361030009)	Philadelphia, PA (421010024)			
Michigan	1	Suffolk, NY (361030009)					
Mississippi	8	East Baton Rouge, LA (220330003)	Brazoria, TX (480391004)	Harris, TX (482010051)	Harris, TX (482010055)	Harris, TX (482010062)	Harris, TX (482010066)
		Harris, TX (482011039)	Tarrant, TX (484391002)				
New Jersey	3	Suffolk, NY (361030002)	Suffolk, NY (361030009)	Philadelphia, PA (421010024)			
North Carolina	3	Suffolk, NY (361030002)	Suffolk, NY (361030009)	Philadelphia, PA (421010024)			
Ohio	3	Suffolk, NY (361030002)	Suffolk, NY (361030009)	Philadelphia, PA (421010024)			
Oklahoma	1	Tarrant, TX (484391002)					
Pennsylvania	2	Suffolk, NY (361030002)	Suffolk, NY (361030009)				
Tennessee	7	Philadelphia, PA (421010024)	Brazoria, TX (480391004)	Harris, TX (482010051)	Harris, TX (482010055)	Harris, TX (482010062)	Harris, TX (482010066)
		Harris, TX (482011039)					
Texas	1	East Baton Rouge, LA (220330003)					
Virginia	3	Suffolk, NY (361030002)	Suffolk, NY (361030009)	Philadelphia, PA (421010024)			
West Virginia	3	Suffolk, NY (361030002)	Suffolk, NY (361030009)	Philadelphia, PA (421010024)			

TABLE IV.C–21—UPWIND STATE TO DOWNWIND MAINTENANCE "LINKAGES" FOR 8-HOUR OZONE

Upwind State	Number of linkages						
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)					
Alabama	6	DeKalb, GA (130890002)	Fulton, GA (131210055)	Harris, TX (482010024)	Harris, TX (482010029)	Harris, TX (482011050)	Tarrant, TX. (484392003).
Arkansas	4	Dallas, TX (481130069)	Dallas, TX (481130087)	Harris, TX (482011050)	Tarrant, TX (484392003)		
Connecticut	1	Westchester, NY (361192004)					
Delaware	1	Bucks, PA (420170012)					
Florida	4	DeKalb, GA (130890002)	Fulton, GA (131210055)	Harris, TX (482010024)	Harris, TX (482010029)		
Georgia	4	Harris, TX (482010024)	Harris, TX (482010029)	Harris, TX (482011050)	Tarrant, TX (484392003)		
Indiana	4	Fairfield, CT (90010017)	New Haven, CT (90093002)	Westchester, NY (361192004)	Bucks, PA (420170012)		
Kansas	1	Dallas, TX (481130069)					
Kentucky	6	Fairfield, CT (90010017)	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Westchester, NY (361192004)	Bucks, PA. (420170012).

TABLE IV.C–21—UPWIND STATE TO DOWNWIND MAINTENANCE "LINKAGES" FOR 8-HOUR OZONE—Continued

Upwind State	Number of linkages					
		Counties containing downwind 24-hour $PM_{2.5}$ nonattainment sites (monitoring site ID)				
Louisiana	6	Dallas, TX (481130069)	Dallas, TX (481130087)	Harris, TX (482010024)	Harris, TX (482010029)	Harris, TX (482011050)	Tarrant, TX. (484392003).
Maryland	6	Fairfield, CT (90010017)	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Westchester, NY (361192004)	Bucks, PA. (420170012).
Mississippi	7	DeKalb, GA (130890002) Tarrant, TX (484392003)	Fulton, GA (131210055)	Dallas, TX (481130087)	Harris, TX (482010024)	Harris, TX (482010029)	Harris, TX. (482011050).
New Jersey	6	Fairfield, CT (90010017)	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Westchester, NY (361192004)	Bucks, PA. (420170012).
New York	5	Fairfield, CT (90010017)	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Bucks, PA (420170012)	
North Carolina	5	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Westchester, NY (361192004)	Bucks, PA (420170012)	
Ohio	6	Fairfield, CT (90010017)	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Westchester, NY (361192004)	Bucks, PA. (420170012).
Oklahoma	3	Dallas, TX (481130069)	Dallas, TX (481130087)	Tarrant, TX (484392003)			
Pennsylvania	5	Fairfield, CT (90010017)	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Westchester, NY (361192004)	
South Carolina	2	Fulton, GA (131210055)	Harris, TX (482010029)				
Tennessee	5	DeKalb, GA (130890002)	Fulton, GA (131210055)	Bucks, PA (420170012)	Harris, TX (482010024)	Harris, TX (482011050)	
Virginia	6	Fairfield, CT (90010017)	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Westchester, NY (361192004)	Bucks, PA. (420170012).
West Virginia	6	Fairfield, CT (90010017)	Fairfield, CT (90011123)	Fairfield, CT (90013007)	New Haven, CT (90093002)	Westchester, NY (361192004)	Bucks, PA. (420170012).

D. Proposed Methodology To Quantify Emissions That Significantly Contribute or Interfere With Maintenance

In this section, EPA explains its general approach to quantifying the amount of emissions that represent significant contribution and interference with maintenance. EPA then applies that approach for the three different NAAQS being addressed in today's notice: The 1997 ozone NAAQS, the 1997 annual $PM_{2.5}$ NAAQS and the 2006 24-hour $PM_{2.5}$ NAAQS.

With respect to the 1997 ozone NAAQS, we apply this methodology to fully quantify the significant contribution and interference with maintenance for 16 states. We also use the methodology to quantify, for 10 additional states, NO_X emissions reductions that are necessary to make measurable progress towards eliminating their significant contribution and interference with maintenance. Additional information gathering and analysis is needed to determine the extent to which further reductions from these states may be needed to fully eliminate significant contribution and interference with maintenance with the ozone NAAQS. As is further explained in section IV.D.2.b EPA will fully address this issue in a future rulemaking as quickly as possible.

With respect to the annual $PM_{2.5}$ NAAQS, this proposal finds that 24 eastern states have SO_2 and NO_X emission reduction responsibilities. We apply the proposed methodology to fully quantify the SO_2 and NO_X emissions from each of these states that significantly contribute to or interfere with maintenance in downwind areas.

With respect to the 24-hour $PM_{2.5}$ NAAQS, this proposal finds that 25 eastern states have emission reduction responsibilities. We use the proposed methodology to quantify emissions reductions that these states must achieve to make, at a minimum, measurable progress towards eliminating the state's significant contribution and interference with maintenance. Further analysis will be needed to determine if these reductions are sufficient to fully eliminate any or all of these states' significant contribution and interference with maintenance for purposes of the 24-hour $PM_{2.5}$ standard. As is explained in greater detail in section IV.D.2.a, EPA intends to finalize, to the extent possible a determination of the complete amount of emissions that represents significant contribution and interference with maintenance. If further analysis shows that the amounts of emissions proposed in today's notice include all emissions that significantly contribute or interfere with maintenance of the 24-hour $PM_{2.5}$ standard or that more SO_2 emissions should be included, we believe that we will be able to issue a supplemental proposal and finalize a rule fully quantifying significant contribution and interference with maintenance with respect to the 24-hour $PM_{2.5}$ standard. If further analysis shows that other reductions should be considered as part of significant contribution or interference with maintenance with respect to the 24-hour $PM_{2.5}$ standard these emissions would be fully addressed in a separate rulemaking effort.

1. Explanation of Proposed Approach To Quantify Significant Contribution

After using air quality analysis to identify upwind states that are "linked" to downwind air quality monitoring sites with nonattainment and maintenance problems because the upwind states' emissions contribute one percent or more to the air quality value at the downwind site, EPA quantifies the portion of each state's contribution that constitutes its "significant contribution" and "interference with maintenance."

This section describes the methodology developed by EPA for this analysis and then explains how that methodology is applied to measure significant contribution and interference with maintenance with respect to the $PM_{2.5}$ NAAQS and the ozone NAAQS. For this portion of the analysis, EPA expands upon the methodology used in the NO_X SIP Call and CAIR, but modifies it in significant respects. In the NO_X SIP Call and CAIR, EPA's methodology relied upon defining significant contribution as those emissions that could be removed with the use of "highly cost effective" controls. In this action, rather than relying solely on determining reductions based on "highly cost effective" controls, EPA uses a number of factors that account for both cost and air quality improvement. Furthermore, unlike the NO_X SIP Call and CAIR where EPA only defined an amount of reductions needed to address significant contribution to nonattainment, EPA is proposing to define an amount of emissions reductions that addresses both significant contribution to nonattainment and interference with maintenance.

The methodology takes into account both the DC Circuit Court's determination that EPA may consider cost when measuring significant contribution, *Michigan,* 213 F.3d at 679, and its rejection of the manner in which cost was used in the CAIR analysis, *North Carolina,* 531 F.3d at 917. It also recognizes that the Court accepted—but did not require—EPA's use of a single, uniform cost threshold to measure significant contribution. *Michigan,* 213 F.3d at 679.

The methodology defines each state's significant contribution and interference with maintenance as the emissions that can be eliminated for a specific cost. Unlike the NO_X SIP Call and CAIR, where EPA's significant contribution analysis had a regional focus, the methodology used in today's proposal focuses on state-specific factors. The methodology uses a multi-step process to analyze costs and air quality impacts, identify appropriate cost thresholds, quantify reductions available from EGUs in each state at those thresholds, and consider the impact of variability in EGU operations.

In step one, EPA identifies what emissions reductions are available at various costs, quantifying emissions reductions that would occur within each state at ascending costs per ton of emissions reductions. For purposes of this discussion, we refer to these as "cost curves".

In step two, EPA uses an air quality assessment tool to estimate the impact that the combined reductions available from upwind contributing states and the downwind state, at different cost-per-ton levels, would have on air quality at downwind monitor sites that had nonattainment and/or maintenance problems.

In step three, EPA examines cost and air quality information to identify cost "breakpoints." Breakpoints are the places where there is a noticeable change on one of the cost curves, such as a point where a large reduction occurs because a certain type of emissions control becomes cost-effective. EPA then uses a multi-factor assessment to determine the amount of emissions that represents significant contribution to nonattainment and interference with maintenance. The factors considered include both the air quality and cost considerations used in developing the breakpoints along with additional air quality and cost considerations. This assessment is performed for each transported NAAQS pollutant or precursor which EPA has concluded must be regulated due to its impact on downwind receptors. In this rule, as discussed in section IV.B, EPA is proposing to regulate SO_2 and NO_X. The methodology also allows EPA, where appropriate, to define multiple cost thresholds that vary for a particular pollutant for different upwind states.

In step four, EPA quantifies the emissions reductions available in each "linked" state at the appropriate cost threshold. This information is then used to develop a state "budget," representing the remaining emissions for the state in an average year, and to identify a variability limit associated with that budget. These budgets and variability limits are used to develop enforceable requirements under the proposed and two alternative remedy options. State emissions budgets are discussed in section IV.E and the variability limit is discussed in section IV.F.

EPA's proposed methodology considers both cost and air quality factors to address complex circumstances. We believe it is important to consider both factors because circumstances related to different downwind receptors can vary and consideration of multiple factors can help EPA appropriately identify each state's significant contribution under different circumstances. For instance, there may be cases when upwind states contributing to a specific downwind nonattainment area have already done a great deal to reduce emissions while the downwind state in which the nonattainment area is located has done very little. Conversely, the downwind state may have made large reductions while one or more contributing upwind states may have done very little. There may be cases where some states (upwind or downwind) have large emissions (and a correspondingly large impact downwind) not because their sources are poorly controlled, but because they have a greater number of sources—the operation of which is critical to the reliability of the electric grid. Conversely, there may be cases where a state (upwind or downwind) contributes less in total emissions because it has a smaller number of plants, but those plants are poorly controlled and could be better controlled at a relatively low cost.

Air quality factors alone are not able to discern these types of differences. Using both air quality and cost factors allows EPA to consider the full range of circumstances and state-specific factors that affect the relationship between upwind emissions and downwind nonattainment and maintenance problems. For example, considering cost takes into account the extent to which existing plants are already controlled as well as the potential for, and relative difficulty of, additional emissions reductions. Therefore, EPA believes that it is appropriate to consider both cost and air quality metrics when quantifying each state's significant contribution.

This methodology is consistent with the statutory mandate in section 110(a)(2)(D)(i)(I) which requires upwind states to prohibit emissions that significantly contribute to nonattainment or interfere with maintenance in another state, but does not shift the responsibility for achieving or maintaining the NAAQS to the upwind state.

In developing and implementing this methodology, EPA was cognizant of a number of factors. First, in many areas, transported emissions are a key component of the downwind air quality problem. Second, there are large amounts of low cost emission reduction opportunities in upwind states. Third, EPA recognizes that section 110(a)(2)(D) does not grant EPA authority to require emissions reductions solely because they provide large health and environmental benefits: reductions required pursuant to section 110(a)(2)(D)(i)(I) must be related to the goal of eliminating upwind state emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind areas.

Fourth, EPA is cognizant of the relationship between the upwind and downwind state requirements in the Act. The Act requires upwind states to eliminate significant interstate pollution transport under section 110(a)(2)(D). It also requires each state to assure attainment and maintenance of the NAAQS within its borders. Thus, a downwind state must adopt controls to demonstrate timely attainment of the NAAQS despite any pollution transport from upwind states that is not eliminated under section 110(a)(2)(D).

Given this structure, interpreting significant contribution and interfere with maintenance inherently involves a policy decision on how much emissions control responsibility should be assigned to upwind states, and how much responsibility should be left to downwind states. In virtually all areas, $PM_{2.5}$ and ozone problems result from a combination of local, in-state, and upwind state emissions. EPA's proposed methodology for determining what portion of a state's total contribution is its significant contribution and interference with maintenance is intended to assign a substantial but reasonable amount of responsibility to upwind states.

There are several reasons that EPA believes upwind state sources contributing to air quality degradation in a downwind state should bear substantial responsibility to control their emissions. First, the plain language of this good neighbor provision requires upwind states to prohibit emissions that significantly contribute to nonattainment or interfere with maintenance in a downwind state. Second, interstate pollution transport increases pollution levels and health risks in the downwind state. Third, the influx of pollution from upwind states raises the pollution level in a downwind state, making it necessary for the downwind state to obtain deeper pollution reductions to attain and maintain air quality standards, which increases costs of control in the downwind state. Fourth, from the standpoint of a downwind state, the pollution contribution of each upwind state adds up to a larger, cumulative degradation of the downwind state's air quality. Fifth, reducing interstate pollution enhances prospects that attainment in downwind states can be achieved within the Act's deadlines and as expeditiously as practicable. All of these points support the position that upwind state sources should bear substantial responsibility to control their emissions.

On the other hand, the proposed methodology ensures that upwind states are not required to shoulder the entire responsibility for the downwind state's attainment and maintenance of the NAAQS. Among other things, our methodology implicitly assumes controls at the same cost per ton level in the downwind state as in the upwind contributing states.[55] In addition, in almost all cases, states with downwind nonattainment and maintenance areas are also required to reduce emissions based on the fact that they are also upwind states that are "linked" to other downwind states with nonattainment and maintenance problems.

The proposed methodology also directly ties each state's reduction requirements to EPA's analysis of that state's significant contribution and interference with maintenance. The required reductions would provide very substantial air quality improvements. For the annual $PM_{2.5}$ standard, EPA projects that this rule will help assure that all but one area in the East attain the standard by 2014. It will also help a number of areas achieve the standard earlier. The methodology provides similar assistance for ozone, assuring upwind reductions that will mitigate the amount that downwind states may need to do. It reduces ozone concentration levels in 2012 and helps assure that even absent this additional local control, all but 3 areas' nonattainment and maintenance problems are resolved by 2014. Air quality in the few areas with remaining problems will be improved, providing both health benefits and assistance for these local areas in meeting the NAAQS requirements.

a. Step 1. Emissions Reductions Cost Curves

The first step in EPA's methodology for determining the quantity of emissions that represents each state's significant contribution is to identify reductions available at different costs. To do so, EPA developed a set of cost curves that show, at various cost increments, the available emissions reductions for EGUs in a state. In other words, EPA determined for specific cost per ton thresholds, the emissions reductions that would be achieved in a state if all EGUs in that state used all emission controls and emission reduction measures available at that cost threshold. The zero point of the curve shows what emissions would occur absent any additional investment in emissions reductions (*i.e.*, the base case emissions). Additional points on the curves show the emissions that would occur after the installation of all controls that could be installed at specific cost levels (dollars per ton of emissions reduced). In developing these cost curves, EPA used IPM to identify costs for reducing emissions from EGUs by modeling emissions reductions available at multiple cost increments. EPA also applied the same cost constraint for each state in each modeling iteration. For example, in one iteration, all covered sources in the states examined were constrained to emit at levels achievable by the application of all controls available for \$100/ton. In a second iteration, all states examined were assumed to achieve all reductions in each state that were available at \$200/ton. The resulting cost curves for SO_2 and annual NO_X can be found in section IV.D.2.a of this preamble and the curves for ozone season NO_X in section IV.D.2.b. For more detail on the development of the cost curves, *see* the TSD, "Analysis to Quantify Significant Contribution," in the docket for this rule.

Although the cost curves presented in this proposal only include EGU reductions, EPA also conducted a preliminary assessment of reductions available for source categories other than EGUs. This preliminary assessment suggested that there likely would be very large emissions reductions available from EGUs before costs reach the point for which non-EGU sources have available reductions. EPA therefore initially created cost curves based solely on reductions from EGUs and determined appropriate cost thresholds based on that analysis. EPA then re-examined non-EGUs to determine the accuracy of its initial assumptions that there were little or no reductions available from non-EGUs at costs lower than the thresholds that EPA had chosen. EPA's analysis of the costs of and opportunities for non-EGU emissions reductions is discussed in more detail in section IV.D.3, later. For the reasons explained in that section, EPA believes there are little or no non-EGU reductions available at the cost thresholds used in this rule. Therefore, EPA believes it is reasonable at this time to use cost curves that include only EGU reductions. However, EPA is continuing to conduct analyses and believes that it will be necessary to further consider non-EGU emission reduction opportunities in future transport rules.

To develop cost curves, emissions available at various costs were assessed in 2012 for ozone season NO_X and 2014 for annual NO_X and SO_2. As described in section V.C, EPA coordinated the deadlines for eliminating significant contribution and interference with maintenance with the NAAQS attainment deadlines for downwind states and determined that all significant contribution and interference with maintenance with respect to the 1997 and 2006 $PM_{2.5}$ NAAQS must be eliminated by 2014, or as expeditiously as practicable. The cost curves show, among other things, that the amount of emissions reductions that can be achieved for a given cost varies over

[55] We also recognize that there can be reasons to depart from an equal cost per ton allocation of responsibility before a receptor's attainment and maintenance problem is fully resolved, such as when a receptor's air quality problem has an unusually high local component.

time. This is true because, among other things, control options that are available in a longer timeframe may not be available in a shorter timeframe. For instance, it takes approximately 27 months to build a flue gas desulfurization unit (FGD, or "scrubber") to reduce SO_2 emissions (Boilermaker Labor Analysis and Installation Timing, USEPA, March 2005), so if this rule is finalized in mid-2011, emissions reductions from scrubbers by 2012 or 2013 can only reasonably be achieved if that scrubber either exists today, or if it is currently under construction. However, by 2014, additional reductions could be obtained from the construction of new scrubbers. It takes approximately 21 months to construct a selective catalytic reduction (SCR) unit to reduce emissions of NO_X. (Boilermaker Labor Analysis and Installation Timing, USEPA, March 2005).

There are approximately 30 months between mid-2011 (when the Agency anticipates finalizing this rule) and January 2014 (the proposed Phase 2 compliance deadline). EPA believes this is sufficient time for sources to install the advanced emissions controls projected to be retrofit. EPA expects about 14 GW of FGD and less than 1 GW of SCR capacity to be retrofit for Phase 2 of this rule. This is significantly less than the capacity that was retrofit in the same length of time after CAIR was finalized. EPA is not aware of problems or issues with sources meeting the CAIR compliance deadlines, either in equipment deliveries or labor availability. EPA believes the proposed Transport Rule compliance deadlines are reasonable, and will result in emissions reductions as quickly as practicable, delivering health benefits to the public and aiding states with NAAQS attainment deadlines.

EPA requests comment on the schedule for scrubber and SCR installations, the availability of boilermaker labor, and any comment on whether there might be alternative post-combustion cost-effective technologies that could reduce SO_2 and/or NO_X emissions. We also solicit comment on whether advanced coal preparation processes might provide emissions reductions at the significant contribution cost levels identified in this proposal, whether such processes have been commercialized, and what the costs will be. In addition, EPA seeks comment on, whether other factors, such as other EPA regulatory actions, will create an increase in boilermaker demand earlier than today's proposal, in 2010 and beyond. We solicit comments on whether other factors might increase demand for boilermakers or control equipment, and what these factors would be. Comments in support of or opposed to the proposed compliance deadlines should include information to support the commenter's position.

Unlike add-on pollution controls such as scrubbers and SCRs, EPA believes that low-NO_X burners could be installed by 2012. *See* TSD, "Installation Timing for Low NO_X Burners," in the docket for this rule.

EPA also believes that sources can switch coals by 2012. Eastern bituminous coals used for power generation typically have more than sufficient sulfur content to facilitate highly efficient collection of fly ash in a cold-side electrostatic precipitator (ESP). Some ESPs that operate at acceptably high collection efficiency when using a high-or medium-sulfur bituminous coal may experience some loss in collection efficiency when a lower sulfur coal is used. Whether this occurs on a specific unit, and the extent to which it occurs, would depend on the design margins built into the existing ESP, the percentage change in coal sulfur content, and other factors. Relatively inexpensive practices to maintain high ESP performance on lower sulfur bituminous coals are available and are being used successfully where necessary. These include a range of upgrades to ESP components and flue gas conditioning.

EPA assumes in the Transport Rule analysis that it will not be necessary for units that switch from higher to lower sulfur bituminous to make a costly replacement of the ESP. EPA's analysis therefore does not add capital or operations and maintenance costs for coal switching from higher to lower sulfur bituminous coals.

EPA's analysis does not allow a unit designed for bituminous to switch to (very low sulfur) subbituminous coal unless the unit has demonstrated that capability in the past. EPA assumes units with that capability have already made any investments needed to handle a switch to subbituminous coals. EPA therefore assumes that any modeled coal switching from bituminous to subbituminous has no cost or schedule impact.

EPA requests comment on the reasonableness of EPA's assumption that coal switching within the bituminous coal grades will have relatively little cost or schedule impact on most units.

b. Step 2. Performing the Air Quality Assessment

In the second step, EPA uses an air quality assessment tool to estimate the impact of the upwind emissions reductions on downwind ambient concentrations.[56] This tool is useful for identifying cost breakpoints for significant improvements in downwind air quality changes, including estimated effects on downwind attainment. While less rigorous than the air quality models used for attainment demonstrations, EPA believes this air quality assessment tool is acceptable for assessing the impact of numerous options on upwind reductions in the process of identifying upwind state significant contribution. It allows the Agency to analyze many more potential scenarios than the time- and resource-intensive more refined air quality modeling would permit. This tool assesses the impact that reductions at a given cost breakpoint from all of the contributing states (as well as the state with the nonattainment area itself) had on pollutant concentrations at that downwind area. The resulting information is used in step three. For each downwind area with a nonattainment and/or maintenance problem, it shows the total improvement in air quality for each cost level and associated pollutant reduction, the amount of the remaining problem caused by each upwind state (by constituent), and the amount of the remaining problem caused by sources within the state (by constituent). It also shows, overall, how much of the downwind air quality problem had been addressed at different cost levels. More detail on the tool itself, what EPA has done to verify the underlying assumptions, and the specific application of the tool to examining significant contribution for ozone and $PM_{2.5}$ can be found in the TSD, "Analysis to Quantify Significant Contribution," in the docket for this rule.

c. Step 3. Identifying Appropriate Cost Thresholds

In the third step of this analysis, EPA examines the information developed in the first two steps to identify potential cost thresholds. It then uses a multi-factor assessment to identify which cost

[56] As is discussed in the RIA, EPA also used the CAMx model to perform air quality analysis of its proposed remedy to address significant contribution. Results from this modeling will not exactly correspond to results from the air quality tool both because the inputs to the air quality modeling are different and the sophisticated model more fully accounts for the complex air chemistry interactions. The full air quality modeling looks at the remedy, including reductions in upwind states that do not contribute as well as the impacts of the variability provisions discussed later in this section. It also provides a metric against which to evaluate the air quality assessment tool.

threshold [57] or thresholds should be used to quantify states' significant contribution and interference with maintenance. This new methodology responds to the Court's statements in *North Carolina* v. *EPA* both criticizing the manner in which cost was used in the CAIR rule and acknowledging its prior acceptance (in *Michigan* v. *EPA*, 213 F.3d 663) of EPA's use of a uniform cost threshold and the uniform control requirements associated with the use of such a cost threshold. *See North Carolina* v. *EPA*, 531 F.3d at 908, 917.920. In both the NO_X SIP Call and CAIR, EPA evaluated the cost of controls relative to the cost of controls required by other CAA regulations to identify a single cost threshold referred to as the "highly-cost-effective" threshold. In contrast, in this proposed rule, EPA considers multiple factors to identify appropriate cost thresholds, allowing EPA to give greater weight to air quality considerations and making it possible to tailor the significant contribution measurement more closely to different conditions in different groups of states.

This step of the analysis begins with an examination of the cost and air quality data to identify breakpoints on the emissions reductions cost curves developed in steps 1 and 2 related to (1) air quality (*e.g.*, points at which all areas (other than those with an unusually predominant local pollution problem) reach attainment and have maintenance fully addressed), and/or (2) cost (*e.g.*, points at which significant reductions are available because a certain technology is widely deployed). EPA identifies potential breakpoints and then uses a multi-factor assessment to evaluate whether one or more of the potential breakpoints represent a reasonable cost at which to define significant contribution for some or all upwind states. The factors in this multi-factor assessment can be divided into two broad categories: Those that focus on air quality considerations and those that focus on cost considerations. Air quality considerations include, for example, how much air quality improvement in downwind states results from upwind state emissions reductions at different levels; whether, considering upwind emissions reductions and assumed local (in-state) reductions, the downwind air quality problems would be resolved; and the components of the remaining downwind air quality problem (*e.g.*, is it a predominantly local or in-state problem, or does it still contain a large upwind component). Cost considerations include, for example, how the cost per ton compares with the cost per ton of existing federal and state rules for the same pollutant, and whether the cost per ton is consistent with the cost per ton of technologies already widely deployed (similar to the highly-cost-effective criteria used in both the NO_X SIP Call and CAIR); the cost increase required to achieve the next increment of air quality improvement; and whether, given timing considerations, emissions reductions requirements could be more costly than indicated in the modeling because sources could choose one short-term solution and then switch to another long-term solution (*e.g.*, switching coals can involve plant modifications. While these costs are low when amortized over a number of years, if a source quickly installs controls, and switches coals again, costs may be higher than projected).

Because upwind state sources should bear substantial responsibility for controlling emissions that contribute to air quality degradation in downwind states, EPA believes that cost per ton levels that are consistent with widely deployed existing controls, or are within the cost per ton range of controls already required by existing and proposed Federal and State rules (*i.e.*, similar to the highly cost effective concept in the NO_X SIP Call and CAIR), are reasonable for upwind states from a cost standpoint. Higher cost per ton levels also may be reasonable for upwind states based on examination of air quality and cost factors. One reason is that achieving attainment and maintenance of the air quality standard may require controls in upwind and downwind states that are more costly than previous controls (particularly if it is a new standard).

Based on this multi-factor assessment, EPA identifies a specific cost per ton threshold for quantifying the amount of significant contribution from each state for each precursor pollutant. While we continue to believe that under certain circumstances it may be appropriate for us to use a single uniform cost per ton threshold to quantify significant contribution for all states, we believe it is also important to retain the flexibility to use multiple cost thresholds. For example, we believe it is appropriate to use multiple thresholds where one group of states can, for a lower cost, eliminate nonattainment and maintenance for all the downwind nonattainment and maintenance areas to which they are linked.

d. Step 4. Identify Required Emissions Reductions

In the final step of this analysis, EPA uses the cost thresholds identified in the previous step to determine, on a state-by-state basis, the amount of emissions that could be reduced at a specific cost. The results of this analysis are used to develop the state budgets and variability limits, which are in turn used to implement the requirements to eliminate significant contribution and interference with maintenance. *See* sections IV.E and IV.F.

2. Application

The discussion that follows explains how the methodology described previously was applied to quantify significant contribution with respect to the 1997 and 2006 $PM_{2.5}$ NAAQS and the 1997 ozone NAAQS. EPA also believes that the methodology proposed today could also be used to address transport concerns under other NAAQS, including revisions to the ozone and $PM_{2.5}$ NAAQS.

All of the air quality considerations included in the multi-factor assessment are based on analysis using the air quality assessment tool. EPA believes that it is appropriate to use this tool because of the advantages it has over more refined air quality modeling to perform analysis of a large number of scenarios very quickly (more refined air quality modeling can take several months, while multiple scenarios can be evaluated using the air quality assessment tool in a single day). EPA has done more refined air quality modeling of the proposed emissions budgets. The more refined air quality modeling confirms EPA's overall methodology, but does suggest that, in the case of daily $PM_{2.5}$, the air quality assessment tool slightly over-predicts the air quality benefit of the proposed reductions.

For this reason, EPA is also requesting comment on whether we should modify our conclusions regarding the amount of specific states' significant contribution and interference with maintenance; whether there are ways to use our air quality modeling in conjunction with the air quality assessment tool to carry out the significant contribution analysis in a way that would not extend the time needed to complete this rulemaking; and whether there are ways to improve the air quality assessment tool.

[57] The cost thresholds identified in today's proposal are specific to the section 110(a)(2)(D) requirements for the states and NAAQS considered in this proposal. They do not represent an agency position on the appropriateness of such cost thresholds for any other application under the Act.

a. Specific Application to $PM_{2.5}$

(1) Year for Quantifying Significant Contribution

EPA's significant contribution analysis for $PM_{2.5}$ used a multi-factor assessment to identify cost thresholds for 2014. EPA believes this is the most appropriate year to consider because it is consistent with attainment dates for both the annual and daily $PM_{2.5}$ standards. Furthermore, EPA believes that 2014 provides sources sufficient lead time to install emissions controls or take other actions necessary to achieve the required reductions. After determining the amount of emissions that represents each state's significant contribution, EPA then considers whether it would be appropriate to establish an interim compliance deadline to ensure that the reductions are achieved as expeditiously as practicable. For this part of the analysis, EPA focused on determining what portion of each state's significant contribution could be eliminated by 2012, the first year in which it would be possible to get reductions following promulgation of this rule in 2011. EPA believes it is possible to achieve much of the required emissions reductions by 2012. EPA also believes that it is important to get the reductions as expeditiously as practicable and to coordinate the compliance dates both with the downwind states" maximum attainment deadlines and with the requirement that they eliminate nonattainment as expeditiously as practicable.

(2) Step 1. Emissions Reductions Cost Curves

This subsection provides more detail on the cost curves that EPA developed to assess the costs of reducing SO_2 and NO_X to address transport related to $PM_{2.5}$. It summarizes the information from the curves and then provides EPA's interpretation of that information. EPA uses the information from the cost curves in step 3 to quantify the cost per ton of emissions reductions which should be used to calculate each state's significant contribution and interference with maintenance, and the resulting state-specific emissions budgets.

To measure significant contribution and interference with maintenance with respect to the $PM_{2.5}$ NAAQS, EPA developed cost curves showing the annual NO_X and annual SO_2 reductions available in 2014 at different cost increments. Specifically, EPA developed cost curves that show reductions available in 2014 from EGUs at various costs (in 2006 $) up to $2,500/ton for annual NO_X, $5,000/ton for ozone season NO_X, and $2,400/ton for SO_2. For example, this means that EPA examined reductions of annual NO_X that are available at a cost of $2,500 per ton or less. For SO_2, the projected cost considered for reducing a ton of emissions is $2,400 or less.

Table IV.D–1 shows the annual NO_X emissions from EGUs at various levels of control cost for 2014.

TABLE IV.D–1—2014 ANNUAL NO_X EMISSIONS FROM ELECTRIC GENERATING UNITS FOR EACH STATE IN THE TRANSPORT REGION AT VARIOUS COSTS

[(2006 $) per ton (thousand tons)]

Marginal cost per ton	Base case level	$500	$1,500	$2,500
Alabama	119	62	62	50
Connecticut	8	8	8	8
Delaware	6	6	6	6
Florida	196	138	113	80
Georgia	48	46	45	45
Illinois	80	56	56	56
Indiana	201	114	114	107
Iowa	68	56	50	47
Kansas	79	38	36	35
Kentucky	149	72	72	71
Louisiana	46	37	37	28
Maryland	36	36	36	36
Massachusetts	13	13	13	13
Michigan	99	68	68	66
Minnesota	55	38	38	38
Missouri	83	82	61	55
Nebraska	53	34	28	28
New Jersey	27	23	23	20
New York	36	35	32	31
North Carolina	63	63	62	61
Ohio	165	104	98	88
Pennsylvania	205	123	122	86
South Carolina	48	36	36	35
Tennessee	69	29	29	29
Virginia	38	37	37	36
West Virginia	100	54	49	45
Wisconsin	55	44	43	41
Total	2,144	1,455	1,375	1,241

Before applying the information in the cost curves in step 3 of the analysis, EPA evaluated the cost curves to better understand how reductions at various cost levels reflect changes in the generation mix (*e.g.*, dispatch changes, fuel use changes, or installation or operation of controls). From the cost curves, EPA concluded that in 2014, there are large NO_X reductions available at approximately $500/ton. At costs above $500/ton and up to at least $2,500/ton, potential reductions increase slowly. This is because the base case assumed that sources would not run their SCR units unless they are required to run those SCR units pursuant to mandates other than CAIR (which will be replaced by this rule when it is finalized). This is especially relevant for winter use of SCRs. Even without CAIR, the NO_X SIP Call will provide an incentive to run many SCRs during the ozone season.

The cost curves demonstrate that many of these sources would operate their SCR units when emissions reductions that cost $500/ton are required. In addition, at this $500/ton level some additional units would likely install advanced combustion control technology. Below $500/ton, there are very few other NO_X reductions. Significant additional reductions would not be achieved without application of controls costing more than $2,500/ton. In 2014, more reductions could be achieved with installation of additional add-on controls, such as SCR.

The cost curves for SO_2 show the same effect as those for NO_X (large emissions reductions at relatively low costs and additional reductions at relatively high costs) but the effect was not as pronounced. In 2014, more than 1,000,000 tons of SO_2 reductions can be achieved at a cost of less than $200 per ton. Most of these reductions can be achieved by requiring companies to operate existing scrubbers that they would not have an incentive to run absent the requirements of CAIR. Additional reductions can be achieved at higher costs. For instance, in many cases, companies are currently using lower sulfur coals to comply with CAIR, but there is no guarantee they will continue to do so. Many, but not all, of these reduction opportunities (*e.g.*, operating current equipment and continued use of low sulfur coal) are available at below $500/ton.

Table IV.D–2 shows that in 2014 there are increased SO_2 emission reduction opportunities beyond just operating existing scrubbers and switching to low sulfur coal. Installation of new scrubbers becomes feasible by 2014, thus increasing reduction opportunities at costs between $500/ton and $2,000/ton (and above).

TABLE IV.D–2—2014 SO_2 EMISSIONS FROM ELECTRIC GENERATING UNITS FOR EACH STATE IN THE TRANSPORT REGION AT VARIOUS COSTS

[(2006$) per ton (thousand tons)]

Marginal cost per ton	Base case level	$100	$200	$500	$1,000	$1,400	$1,800	$2,000	$2,400
Alabama	322	307	257	171	166	146	101	84	71
Connecticut	6	6	6	6	6	3	3	3	3
Delaware	8	9	9	9	9	9	9	8	8
Florida	195	178	171	117	113	111	79	74	70
Georgia	173	166	136	133	117	101	92	86	67
Illinois	200	185	165	165	164	165	161	155	143
Indiana	804	478	433	328	291	284	242	227	190
Iowa	164	140	130	106	105	104	102	101	70
Kansas	65	64	56	49	46	46	33	31	24
Kentucky	740	275	270	248	196	178	127	115	100
Louisiana	95	95	95	95	95	95	95	82	36
Maryland	45	45	45	45	45	45	42	42	40
Massachusetts	17	18	18	10	10	10	9	9	6
Michigan	276	254	253	214	209	207	177	163	116
Minnesota	62	57	55	49	48	48	48	48	46
Missouri	501	289	238	213	212	212	196	183	94
Nebraska	116	119	113	74	73	71	69	45	33
New Jersey	40	40	27	21	21	20	18	17	14
New York	143	142	143	135	118	114	100	70	63
North Carolina	141	141	141	130	114	104	99	91	63
Ohio	841	583	553	408	294	260	236	221	203
Pennsylvania	975	825	441	337	202	175	154	145	125
South Carolina	156	138	137	134	125	83	78	57	42
Tennessee	600	154	131	127	126	108	108	100	79
Virginia	137	134	134	109	106	93	65	54	45
West Virginia	496	179	170	161	160	143	132	119	98
Wisconsin	117	111	108	97	92	89	87	81	64
Total	7,436	5,133	4,435	3,692	3,263	3,025	2,660	2,410	1,912

(3) Step 2. Air Quality Assessment of Potential Emissions Reductions

After developing cost curves to show the state-by-state cost-effective emissions reductions available, EPA used the air quality assessment tool to evaluate the impact these upwind reductions would have on air quality in "linked" downwind nonattainment and maintenance areas. This section summarizes the results of that evaluation and provides analysis that informs EPA's multi-factor assessment, explained in step 3, later.

EPA performed air quality analysis for each downwind receptor with a nonattainment and/or maintenance problem. For each receptor, EPA assessed the air quality improvement resulting when a group of states, consisting of the upwind states that are "linked" to the downwind receptor (*i.e.*, EPA modeling showed that they exceeded the one percent contribution threshold, based on it's 2012 linkage analysis), and the downwind state where the receptor is located, all made the emissions reductions that EPA identified as available at each cost threshold (as described previously). This analysis did not assume any reductions in upwind states covered by this rule but not "linked" to the downwind receptor (even if the state was "linked" to a different receptor), beyond those assumed in the base case.

The percent emissions reductions (and percent air quality improvement) that could be made by each upwind state in 2014 at different cost per ton levels are shown in Figures IV.D–1 through IV.D–4, later. These figures show the percent reduction in SO_2 emissions as a function of cost (using the emissions at zero dollars per ton in 2014 as the baseline reference). A percentage reduction of zero means that emissions are not reduced from the levels that exist at the 2014 zero dollar per ton (base case) cost level. It is assumed that reductions in SO_2 emissions are linearly and directly proportional to downwind sulfate contributions. In other words, it is assumed that a specific percent reduction in SO_2 emissions would lead to the same percent reduction in air quality sulfate contribution from that upwind state. For example, if a state made a 50 percent reduction in SO_2 emissions, its sulfate contribution to any monitor downwind is assumed to be reduced by 50 percent.

EPA determines the cumulative air quality improvement that could be expected at a particular downwind receptor by multiplying each upwind state's percent reduction by its air quality contribution and summing the results for all upwind states. In EPA's air quality analysis of each downwind receptor, all air quality improvements are measured relative to baseline emissions and air quality contributions in 2012.

Figures IV.D–1 through IV.D–4 show that at increased costs, there are substantial increased emissions reductions. As explained previously, each decrease in emissions is assumed to lead to a corresponding improvement in downwind air quality. These changes apply to both the daily and annual $PM_{2.5}$ NAAQS. While the pattern differs from state to state, many states see noticeable decreases in sulfate contribution for costs of $500/ton or less. Reductions in downwind contribution level off, then many states start to see an additional decrease in contribution at higher costs (in general about $1,500/ton).

Figure IV.D-1 Percent Reduction in Downwind SO_2 Contribution as a Function of Cost in 2014 for DE, FL, KS, LA, MA, and NE.

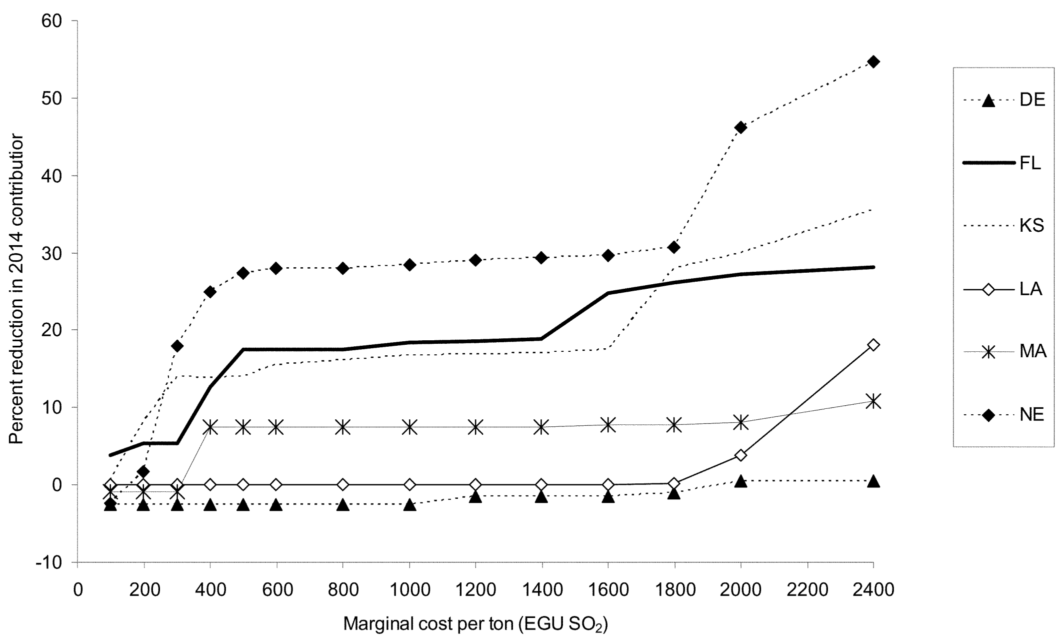


Figure IV.D-2 Percent Reduction in Downwind SO_2 Contribution as a Function of Cost in 2014 for AL, CT, MD, MN, NJ, and SC.

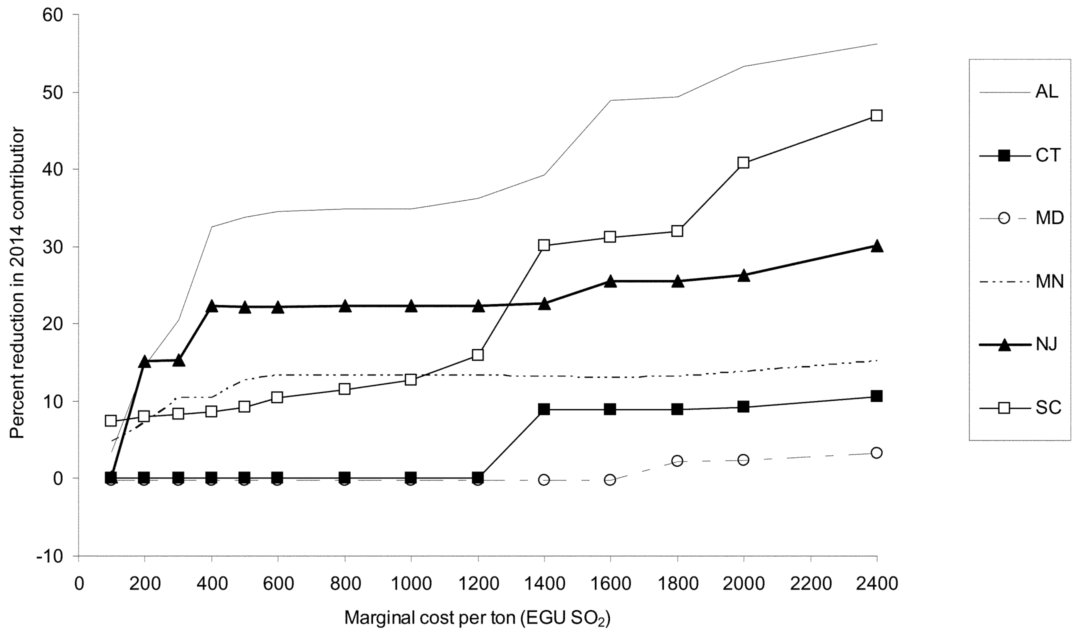


Figure IV.D-3 Percent Reduction in Downwind SO_2 Contribution as a Function of Cost in 2014 for IA, KY, NY, NC, OH, TN, and VA.

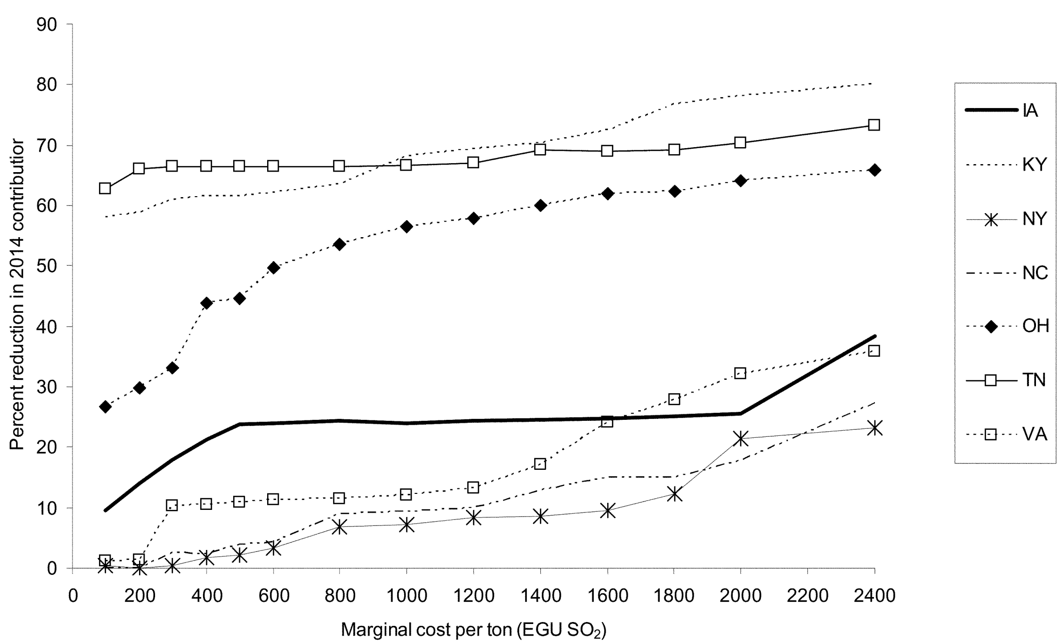
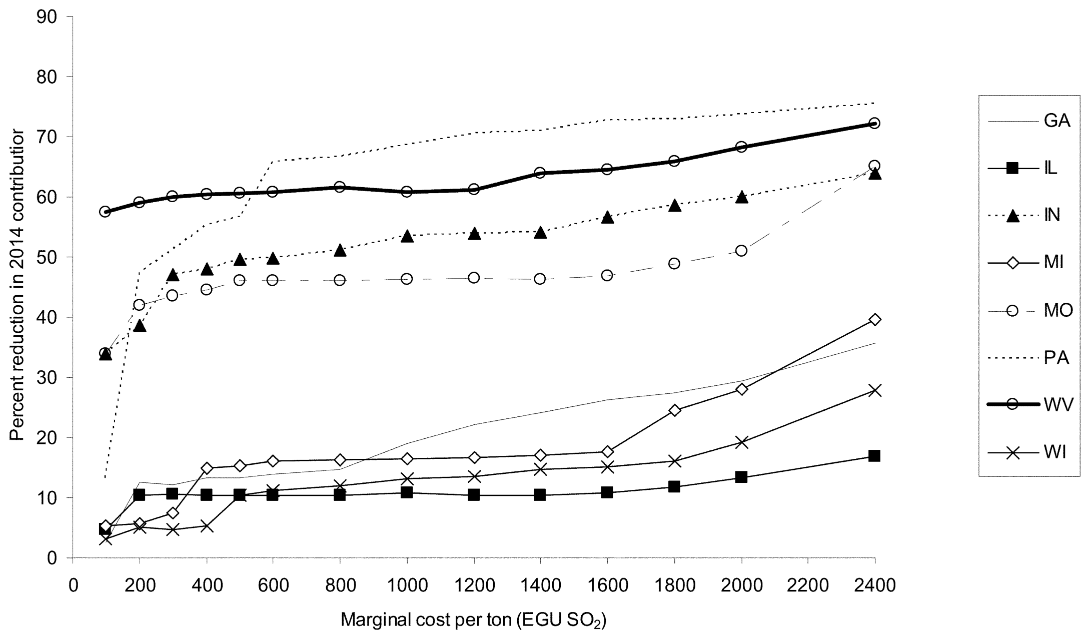


Figure IV.D-4 Percent reduction in downwind SO_2 contribution as a function of cost in 2014 for GA, IL, IN, MI, MO, PA, WV, and WI.



EPA also identified the overall air quality reductions projected by the air quality assessment tool at downwind nonattainment and maintenance receptor locations. As explained previously, the multi-factor assessment in step 3 analyzed the results from the downwind receptor analysis in step 2 for the annual and daily $PM_{2.5}$ standards. Tables IV.D–3 and IV.D–4 show the air quality improvements in 2014 from the emissions reductions projected to occur at various costs. Table IV.D–4 also shows the average decrease in ambient daily $PM_{2.5}$ for different sets of downwind sites for various reductions in SO_2.

TABLE IV.D–3—ESTIMATED NUMBER OF NONATTAINMENT AND/OR MAINTENANCE MONITOR SITES IN 2014 FOR ANNUAL $PM_{2.5}$

[As a function of SO_2 cost-per-ton levels]

Marginal cost per ton	2014	2014
	Number of remaining nonattainment monitor sites	Number of remaining nonattainment and maintenance monitor sites
>$0	12	19
>$100	3	6
>$200	2	3
>$300	2	3
>$400	1	2
>$500	1	2
>$600	1	1
>$800	1	1
>$1,000	1	1
>$1,200	1	1
>$1,400	1	1
>$1,600	1	1
>$1,800	0	1
>$2,000	0	1
>$2,400	0	1

TABLE IV.D–4—DAILY AIR QUALITY IMPACTS VS. SO_2 COST PER TON LEVELS IN 2014

Marginal SO_2 cost per ton	Number of remaining nonattainment and maintenance monitor sites	Air quality improvement (average µg/m∧3 Reduction) relative to 2014 base case (zero dollars/ton)		
		All sites in 2012 base	6 selected sites *	3 selected sites **
>$0	64	0.0	0.0	0.0
>$100	16	3.7	2.0	1.8
>$200	12	4.4	2.4	2.1
>$300	8	4.7	2.6	2.3
>$400	* 6	5.0	2.9	2.6
>$500	6	5.1	3.0	2.6
>$600	6	5.3	3.1	2.8
>$800	6	5.4	3.3	2.9
>$1,000	6	5.6	3.4	3.0
>$1,200	6	5.7	3.4	3.0
>$1,400	6	5.8	3.5	3.1
>$1,600	5	6.0	3.6	3.2
>$1,800	4	6.2	3.7	3.3
>$2,000	** 3	6.4	3.9	3.4
>$2,400	1	6.8	4.1	3.7

* The six sites are: Allegheny County, PA (2 sites); Baltimore County, MD; Wayne County, MI; Lake County, IN; Cook County, IL.
** The three sites are: Lake County, IN; Cook County, IL; Allegheny County, PA.

A number of conclusions can be drawn from Tables IV.D–3 and IV.D–4. Very low cost SO_2 reductions result in significant air quality benefits.[58] As explained previously, this is because there are significant reductions available from sources that operate existing scrubbers and, in a number of cases, use relatively low cost, lower sulfur coal. At the same time, in 2014 enough lead time exists for considerable emission reduction opportunities from new scrubber installations. Other programs are also achieving reductions (for example, some state rules and enforcement consent decrees require SO_2 and NO_X reductions in 2013 and 2014). The analysis also shows that higher cost reductions continue to provide downwind air quality improvements.

[58] Measured in terms of downwind area nonattainment and/or maintenance concerns being addressed. This is also true in terms of improvements in air concentrations of $PM_{2.5}$.

(4) Identifying Cost Thresholds

(a) Considerations for 2014

For $PM_{2.5}$, EPA considered three cost breakpoints for SO_2 and one for NO_X. First EPA looked at a point at which EGUs operated all installed controls, continued to burn coals with sulfur contents consistent with what they were burning in 2009, and operated any additional controls they are currently planning to install by 2014. For NO_X, this point is similar to the $500/ton cost. For SO_2, it is similar to the $300 to $400 cost. EPA believes this is an appropriate starting point, because if a state is "linked" to a downwind state (*i.e.*, if our air quality analysis showed it was contributing above the 1 percent threshold), EPA believes it is appropriate to prohibit that state from increasing its emissions which could worsen downwind air quality problems. EPA then considered what additional cost thresholds should be considered. For SO_2 EPA considered two breakpoints: (1) $2,000/ton SO_2 and (2) $2,400/ton SO_2. EPA's state-by-state cost modeling at that point indicates that scrubbers would be installed on units generating about 20 GW of electricity. Since slightly over 21 GWs of scrubbers were installed in both 2008 and 2009 (*see* EPA Analysis of Alternative SO_2 and NO_X Caps for Senator Carper—July 31, 2009 Appendix B, page 15), EPA believes that it is clearly possible for the power sector to install at least that quantity of scrubbers by 2014. The $2,400/ton SO_2 breakpoint represents the point where analysis from the air quality assessment tool projects that both nonattainment and maintenance concerns would be fully addressed in all areas, except for Allegheny County, Pennsylvania, when considering reductions from only states that contribute more than 1 percent.[59] As is explained later in this section, EPA believes that the monitor in Allegheny County that remains in nonattainment is in an area where the air quality problem is primarily local. Since EPA's analysis suggests that the only remaining nonattainment problem is primarily local, EPA did not consider higher cost thresholds.

EPA did not consider additional cost thresholds for NO_X beyond $500/ton because there are minimal additional NO_X reductions until one considers cost levels higher than $2,400/ton, and SO_2 reductions are generally more effective than NO_X reductions at reducing $PM_{2.5}$. EPA did not consider lower cost thresholds than $2,000/ton for SO_2 because: There are clearly continued air quality benefits at higher costs (as evidenced by increases in average air quality improvements in downwind sites); there is very little change in the number of downwind nonattainment and/or maintenance sites, indicating that the number of upwind states contributing would not be expected to change much; and costs of up to $2,000/ton of SO_2 are reasonable in comparison to other existing regulations.

First EPA assessed $2,000/ton. Reductions at $2,000/ton would improve air quality at several locations with nonattainment and/or maintenance problems. We also believe that, as explained in the introduction to this section, it is reasonable to require a substantial level of control of upwind state emissions that significantly contribute to nonattainment or maintenance problems in another state. We believe that $2,000/ton is reasonable for SO_2 considering that this cost per ton level is based on EGU control technologies that are proven and already widely deployed. Furthermore, compared to other control measures that address SO_2, this cost per ton level is relatively low. A survey of the control options that EPA examined in the $PM_{2.5}$ RIA shows that non-EGU SO_2 reduction opportunities cost from $2,270/ton to over $16,000/ton.

While analysis with the air quality assessment tool shows that a site in Allegheny County, Pennsylvania would be in nonattainment and two other sites—Lake County, Indiana and Cook County, Illinois—would have maintenance problems, if we assume reductions at $2,000/ton and additional reductions made by states because of their contribution to other downwind sites that do not contribute to these three problem areas, the maintenance problems in Lake County, Indiana and Cook County, Illinois would be resolved and only Allegheny County, Pennsylvania, would continue to have a nonattainment/maintenance problem. Because reductions at $2,000/ton continue to have significant air quality benefit for downwind sites with nonattainment and/or maintenance problems, it has been demonstrated historically that the amount of control equipment that is projected to be needed at $2,000/ton could be installed in the timeframe required and these costs are reasonable when compared to other options to reduce SO_2. Therefore, EPA believes that requiring a cost threshold of at least $2,000/ton would be appropriate for determining significant contribution.

Because our analysis shows that one area (Allegheny County, Pennsylvania) would have continuing nonattainment and maintenance problems, EPA continued to perform its multi-factor assessment for the higher $2,400/ton breakpoint to see if any additional emissions should also be considered significant. For this receptor monitor, EPA considered the local circumstances in the Liberty-Clairton area in Allegheny County that were leading to continued nonattainment. It is well-established that, in addition to being impacted by regional sources, the Liberty-Clairton area is significantly affected by a large increment of local emissions from a sizable coke production facility and other nearby sources. (*See http://www.epa.gov/pmdesignations/2006standards/final/TSD/tsd_4.0_4.3_4.3.3_r03_PA_2.pdf*). High concentrations of organic carbon indicate the unique local problem for this location.

Because the remaining $PM_{2.5}$ problem is more local in nature than the problem at other receptors, EPA does not believe that it is appropriate to establish a higher cost threshold solely for states that are "linked" to this monitor.

(b) Amount of Reductions That Could Be Achieved by 2012

After determining that the amount of emissions that could be reduced for $2,000/ton in 2014 is an appropriate quantification of a state's significant contribution, EPA considered whether any of these emissions reductions could be achieved prior to 2014. For the reasons that follow, EPA concluded that significant reductions could be achieved by 2012 and that it is important to require all such reductions by 2012 to ensure that they are achieved as expeditiously as practicable. While EPA believes that it is not possible to require the installation of post-combustion SO_2 controls (scrubbers) or post-combustion NO_X controls (SCRs) before 2014 (because it takes about 27 months to install a scrubber and 21 months to install an SCR), EPA believes that there are significant reductions that can occur earlier. For SO_2, reductions from operating existing scrubbers up to their design removal efficiencies and from the use of lower sulfur coals are possible by 2012. For NO_X, reductions from operating existing SCRs on a year-round basis and up to their design removal efficiencies and the installation of limited amounts of low NO_X burners are possible by 2012. For this reason, EPA believes it is appropriate to require these emissions to be removed in 2012,

[59] When considering all reductions made, including those by states that contribute less than 1 percent, the air quality assessment tool projects that both nonattainment and maintenance will be fully addressed in all areas except for Allegheny County, PA at $2,000/ton.

consistent with the Act's requirement that downwind states attain the NAAQS as expeditiously as practicable. Section IV.E explains how these 2012 emissions reductions requirements are defined.

(c) Off-Ramp for States That Eliminate Their Significant Contribution for Less Than $2,000/Ton

Table IV.D.4, previously, shows that for large numbers of monitoring sites where there are nonattainment and or maintenance problems, those problems are fully resolved before all states achieve all of the emissions reductions that could be achieved at or below $2,000/ton. EPA used the air quality assessment tool to analyze the impact of requiring all states linked to the downwind state site with an air quality problem, as well as the downwind state, to reduce emissions consistent with the levels discussed for 2012 in section IV.D.2.a(2), previously. The air quality assessment tool shows that those 2012 reductions will resolve the nonattainment and maintenance problems for all of the areas to which the following states are linked: Alabama, Connecticut, Delaware, the District of Columbia, Florida, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Nebraska, New Jersey and South Carolina (referred to as group 2 states). EPA also assessed whether, in 2014, the combination of this level of reduction from the group 2 states and the remaining states (referred to as group 1 states) continued to result in all downwind areas—except for Allegheny County, Pennsylvania—fully addressing their nonattainment and or/maintenance problems, and determined that it did.

The states in group 1 and group 2 are rationally grouped considering air quality and cost. EPA proposes that it would not be appropriate to assign the same cost per ton to group 2 and group 1 states because a significantly lower cost per ton was sufficient to resolve air quality problems at all downwind receptors linked to the group 2 states. Although states are linked to different sets of downwind receptors, our analysis indicated that the cost per ton needed to resolve downwind air quality problems varied only to a limited extent among states within group 1 and among states within group 2. The cost per ton did vary greatly between the group 1 and group 2 states. Limitations on the accuracy of our cost and air quality analyses, and the ruling in the *Michigan* decision accepting EPA's prior use of a uniform cost approach, support the decision to use uniform costs for a group of states.

(d) Proposed Cost Thresholds for $PM_{2.5}$

Summary of methodology. In summary, EPA determined that SO_2 emissions that could be reduced for $2,000/ton in 2014 should be considered a state's significant contribution, unless EPA determined that a lesser reduction would fully resolve the nonattainment and/or maintenance problem for all the downwind monitoring sites to which a particular state might be linked. For these "group 2 states" EPA is determining that a lesser reduction of SO_2, based on the amount of SO_2 reductions that can be reasonably achieved by 2012 is appropriate. EPA also determined that all states linked to downwind $PM_{2.5}$ nonattainment and maintenance problems should be required to achieve those emissions reductions that can be reasonably achieved by 2012. Finally, EPA determined that all states linked to downwind $PM_{2.5}$ nonattainment (*see* Table IV.D–5) and maintenance problems should, by 2012, remove all NO_X emissions that can be reduced for $500/ton in 2012.

TABLE IV.D–5—STATES COVERED FOR SO_2 GROUP 1, SO_2 GROUP 2, AND NO_X ANNUAL

States covered	SO_2 group 1	SO_2 group 2	NO_X annual
Alabama		X	X
Connecticut		X	X
Delaware		X	X
District of Columbia		X	X
Florida		X	X
Georgia	X		X
Illinois	X		X
Indiana	X		X
Iowa	X		X
Kansas		X	X
Kentucky	X		X
Louisiana		X	X
Maryland		X	X
Massachusetts		X	X
Michigan	X		X
Minnesota		X	X
Missouri	X		X
Nebraska		X	X
New Jersey		X	X
New York	X		X
North Carolina	X		X
Ohio	X		X
Pennsylvania	X		X
South Carolina		X	X
Tennessee	X		X
Virginia	X		X
West Virginia	X		X
Wisconsin	X		X
Totals	15	13	28

After completing the process to propose appropriate state-by-state cost thresholds, EPA used these thresholds to develop the specific state-by-state budgets. This step in the process is fully described in section IV.E.

(e) Request for Comment on Issues Related to EPA's Modeling Methods

EPA believes that the methodology described previously is a sound and analytically efficient approach to addressing the requirements of 110(a)(2)(D)(i)(I) for the $PM_{2.5}$ standards. While it would be possible for EPA to add additional analytical steps to the methodology, and such analyses would provide more information, EPA believes that the methodology selected strikes an appropriate balance between the competing requirements of comprehensive analysis and timely action. EPA believes that the technical analysis completed provides a sound basis for action. EPA also seeks to avoid burdensome technical analyses which could prevent EPA from fulfilling our obligation to the Court to act in a timely way. In this section, EPA generally requests comment on issues related to its efforts to strike an appropriate balance. EPA identifies several areas of recognized limitations on our methodology, and requests comments both on the implications of these limitations and on possible options for addressing these limitations without unduly delaying necessary action.

(f) Use of Air Quality Assessment Tool; Results of More Detailed Air Quality Modeling Used To Evaluate the Tool

As discussed previously, EPA uses a simplified air quality assessment tool, rather than actual air quality modeling, to identify air quality impacts of the options considered. This assessment tool enables efficient evaluation of multiple options quickly. We did, however, conduct more refined air quality modeling of the select emissions budgets and this more detailed modeling serves as a check on the appropriateness of the method. This check confirmed the directional conclusions of the air quality assessment tool and largely confirmed the more detailed results of the air quality assessment tool, but raised several issues on which EPA is requesting comment.

For the annual $PM_{2.5}$ standard, the air quality assessment tool projected that, after implementation of the proposed FIPs, only one area (Allegheny County, PA) would have a continuing NAAQS air quality problem under the maintenance criteria. The results of the refined air quality modeling are very similar. This modeling projects similar annual $PM_{2.5}$ reductions in downwind states and projects that Allegheny County, PA would remain in nonattainment and that Birmingham, AL would exceed the threshold for "maintenance" by a slight amount (less than 0.1 ug/m ^{3}). Given the unique local nature of the Allegheny County, PA receptor (*see* discussion previously), EPA does not believe that the fact that the air quality assessment tool projects the area to have only a maintenance problem, while the refined air quality modeling suggests that the area would remain in nonattainment, raises any serious issues about the conclusions regarding significant contribution to nonattainment and interference with maintenance with the annual $PM_{2.5}$ standard. Similarly, because the refined air quality modeling projects that Birmingham, AL will exceed the maintenance criteria by only an extremely slight amount and because reductions from nearby point sources will reduce local emissions in the area, EPA does not believe the refined air quality modeling demonstrates that upwind reductions beyond those in the proposed FIPs are required to address significant contribution and interference with maintenance of the annual $PM_{2.5}$ NAAQS in Birmingham. For these reasons, EPA does not believe that the more refined air quality modeling for the annual $PM_{2.5}$ standard changes any of EPA's conclusions with respect to reductions required to eliminate significant contribution and interference with maintenance with respect to this standard. EPA is, however, taking comment on whether Florida, the one group 2 state that was identified as linked to Birmingham, should be moved from group 2 to group 1. EPA notes that no group 2 states are linked to Allegheny County, PA.

For the 24-hour $PM_{2.5}$ standard, the simplified air quality assessment tool results suggest that under EPA's proposed FIPs, only one problem site, Allegheny County, PA, would remain. In contrast, the more refined CAMx air quality modeling results show a greater 24-hour $PM_{2.5}$ problem, with 10 nonattainment and 4 maintenance areas. As described later, EPA is evaluating the impact of this refined air quality modeling on the methodology used and the conclusions it has reached regarding significant contribution and interference with maintenance with regard to the 24-hour $PM_{2.5}$ NAAQS.

EPA has completed some preliminary analysis of the difference between the air quality assessment tool and CAMx results (*see* the TSDs "Analysis to Quantify Significant Contribution" and "Air Quality Modeling"). This analysis suggests that the main difference is that in the winter months, the CAMx modeling shows smaller air quality reductions compared to the assessment tool. This is because the CAMx air quality modeling more accurately reflects the complex nature of the winter portion of the 24-hour $PM_{2.5}$ problem. Unlike summer days, for which sulfate is the dominant contributor to $PM_{2.5}$, sulfate concentrations are typically a lesser contributor to the overall $PM_{2.5}$ concentrations on winter days. Moreover, for winter days, reductions in this already reduced amount of sulfate appear to be less responsive to reductions in SO_2 emissions than for summer days. That is, while for the summer a 50 percent reduction in SO_2 emissions would likely yield a nearly 50 percent reduction in sulfate concentrations, in the winter such a reduction in SO_2 would reduce sulfate by less than 50 percent. Thus, EPA believes that more study of the winter portion of the problem is warranted to address the issues raised by the CAMx modeling. EPA believes it is important to understand the degree to which these winter exceedances are transport-related or locally generated, and the degree to which upwind states' emissions of NO_X, SO_2, and other transported pollutants are significantly contributing to these winter exceedances.

Because the CAMx results indicate additional nonattainment and maintenance areas compared to the air quality assessment tool, EPA requests comment on whether the $2,000/ton cost cutoff for SO_2 resulting from the assessment tool should be raised to a higher cost cutoff. While the CAMx results may suggest that it would be appropriate to use a cutoff greater than $2,000/ton, the results do not suggest that the cutoff could be less than $2,000/ton. Instead, the results confirm the importance of achieving, at a minimum, all reductions available at the $2,000/ton cost threshold.

Additionally, EPA is requesting comment on whether some group 2 states should be moved to group 1. These group 2 states are: Connecticut, Kansas, Maryland, Massachusetts, Minnesota, Nebraska, and New Jersey. These states were all placed in group two because the air quality assessment tool indicates that the 2012 reductions will resolve the nonattainment or maintenance problems at all areas to which they are linked. However, for these states, the CAMx modeling indicates that one or more of the states to which they are linked will have continuing nonattainment and maintenance problems after the implementation of the 2012 reductions.

EPA also notes that during the winter, $PM_{2.5}$ contains a larger nitrate component than in summer months. One reason for this is that some nitrates that are particles in cooler weather volatize and exist as gases during warmer weather. Given this larger contribution from nitrates in the winter, EPA is also taking comment on whether there should be a higher cost threshold for annual nitrogen oxides. This may be appropriate for states that have been identified as contributing significantly to sites that the CAMx air quality modeling continues to show as having a residual nonattainment and/or maintenance concern in 2014.

Finally, EPA requests comment on how and whether EPA should incorporate the use of detailed models such as CAMx into our methodology for significant contribution and interference with maintenance.

(g) Possibility for Emissions Increases in Noncontributing States

EPA also evaluated whether the proposed rule could cause changes in operation of electric generating units in states not regulated under the proposal (that is states not listed in table IV.D–5). Specifically, EPA evaluated whether such changes could lead to increases in emissions in those states, potentially affecting whether they would exceed the 1 percent contribution thresholds used to identify linkages between upwind and downwind states. (*See* sections IV.B and IV.C previously for more discussion of the 1 percent thresholds). Such changes are possible in part because of the interconnected nature of the country's energy system (including both the electricity grid and coal and natural gas supplies). In addition, our models project that the rule affects the cost of coal (generally lowering the cost of higher sulfur coals and raising the cost of lower sulfur coals). If these price effects took place and if the rule is finalized as proposed, sources in states not covered by the proposed rule might choose to use higher sulfur coals. Increased use of such coals could thus increase SO_2 emissions in those states. EPA's modeling confirms this, projecting that, after the proposed rule is implemented in states regulated for SO_2, emissions in some states not covered by the proposed rule would increase (i.e., their emissions are greater in the control case modeling than in the base case modeling). As shown in table IV.D–6, Arkansas, Mississippi, North Dakota, South Dakota, and Texas all exhibit 2012 SO_2 emissions increases over the base case and above 5,000 tons.[60] For reference, we also include the statewide 2012 base case emissions from all sources within the state.

TABLE IV.D–6—UNREGULATED STATES WITH MORE THAN 5,000 TONS OF PROJECTED SO_2 INCREASES UNDER THE PROPOSED TRANSPORT RULE

State	2012 SO_2 increase from base case (thousand tons)	2012 SO_2 base case emissions from all sources (thousand tons)
Arkansas	32	127
Mississippi	18	80
North Dakota	11	94
South Dakota	6	26
Texas	136	640

Further analysis with the air quality assessment tool indicates that these projected increases in the Texas SO_2 emissions would increase Texas's contribution to an amount that would exceed the 0.15 $\mu g/m^3$ threshold for annual $PM_{2.5}$. For this reason, EPA takes comment on whether Texas should be included in the program as a group 2 state.

(h) Providing Downwind States Full Relief From Upwind Emissions

EPA takes very seriously its responsibility to ensure that upwind reductions are made in a timely way so that downwind states can meet their attainment obligations.

EPA recognizes, as discussed previously, that while this proposal fully addresses the annual $PM_{2.5}$ standard, it may not fully address the 24-hour $PM_{2.5}$ standard. Where this may be the case, as explained previously, EPA's air quality modeling shows that the remaining component of non-attainment is almost entirely occurring in the winter months. Also as noted previously the atmospheric chemistry related to secondary particle formation, and the relative importance of particle species such as sulfate and nitrate, is quite different between summer and winter. Because of this, EPA is moving ahead with further efforts, before the final rule is published, to determine the extent to which this winter problem is caused by emissions transported from upwind states and, if this is the case, to identify the total amount of emissions that represents significant contribution and interference with maintenance. To the extent possible, EPA plans to finalize a rule that fully defines this amount.

Based on the information that EPA currently has, EPA believes there are a number of possible outcomes of this further study. Possible outcomes include:

(1) Identification of the additional amount of SO_2 emissions reductions needed to eliminate significant contribution and interference with maintenance from upwind states contributing to the residual 24-hour $PM_{2.5}$ problem sites.

(2) Identification of the additional amount of NO_X emissions reductions needed to eliminate significant contribution and interference with maintenance from upwind states contributing to the residual 24-hour $PM_{2.5}$ problem sites.

(3) Identification of another pollutant that should be considered part of significant contribution and interference with maintenance for states that

[60] While Colorado is also a state that may see projected increases in emissions, it was not within the domain the EPA analyzed.

contribute to the residual 24-hour $PM_{2.5}$ problem sites.

(4) Determination that the reductions proposed in today's rulemaking would fully address significant contribution and interference with maintenance at these sites.

If EPA determines that more SO_2 emissions should be considered part of this amount based on the analysis performed for today's proposal, EPA believes that the next set of emissions that can be reduced above the $2,000/ton threshold would likely still come from the power sector. If EPA determines that more SO_2 emissions reductions are required or that the amount of emissions of SO_2 and NO_X that it has proposed as significantly contributing to nonattainment are the appropriate amounts to address this winter portion of the problem, EPA intends to supplement today's proposal and finalize a rule that would fully addresses emissions that significantly contribute to or interfere with maintenance of the 2006 daily $PM_{2.5}$ standard.

To the extent that EPA determines that more NO_X reductions are needed or that reductions of another pollutant are needed, EPA believes that we could provide the greatest assistance to states in addressing transport by finalizing this rule quickly and promulgating a separate rule to achieve any necessary additional NO_X reductions. This is because those emissions reductions would likely involve placing reduction requirements on sources other than EGUs and that additional approaches would need to be addressed. EPA believes that developing supplemental information to address these sources and concepts would substantially delay publication of a final rule, beyond the anticipated publication of spring 2011.

EPA plans to move forward aggressively in the event that these further reductions are needed. We do not, however, intend to delay the reductions in this proposed rule because those reductions have a substantial impact on states' abilities to attain the NAAQS in the required time period and have large health benefits.

b. Specific Application to Ozone

This section discusses, for the 1997 ozone standards, how EPA applies its multi-step methodology for defining each state's significant contribution. For some aspects of the methodology, further work is needed to complete the methodology for ozone and this further work will be completed in a separate proposal.

(1) Years for Quantifying Significant Contribution

In this subsection, we discuss how EPA identifies for ozone the years to analyze for eliminating significant contribution. Similar to the previous discussion for $PM_{2.5}$, EPA believes that the selection of the year for eliminating significant contribution is informed by the attainment deadline and by the Act's requirement to attain the NAAQS "as expeditiously as practicable."

As noted earlier, the 2012 ozone season is the last ozone season before the 2013 attainment deadline for ozone areas classified as "serious" for the 1997 ozone air quality standards. Thus, for any states "linked" to "serious area" locations for which 2012 is the latest ozone season prior to their attainment deadline, EPA believes that 2012 is the appropriate year for eliminating significant contribution, to the extent that purpose can be achieved given the short time period. Because this proposed rule would not be finalized until 2011, the year 2012 also represents the earliest time by which emissions reductions could be achieved, which is consistent with statutory provisions calling for downwind states to achieve attainment "as expeditiously as practicable." This also is relevant for certain other areas with lower ozone classifications that are projected in our analysis to have continuing air quality problems and to be affected by transported pollution from certain upwind states in amounts greater than the 1 percent threshold.[61]

EPA is concerned that the timing of this rule presents difficult challenges in eliminating significant contribution and interference with maintenance with regard to the 1997 ozone NAAQS by the attainment date. For states with a 2012 (or earlier) attainment date for which we project continuing ozone problems, we are concerned that strict adherence to a 2012 date for reductions could be viewed as an artificial constraint on our ability to require appropriate reductions. EPA believes that the current situation for ozone, involving a transport rulemaking within months of the attainment date (and in a number of cases, after the current attainment date) is a unique situation created by the Court's remand of the CAIR. Under normal circumstances adhering to the CAA schedule for addressing transport within 3 years after a NAAQS is promulgated, transport requirements would be in place years before the attainment date. For purposes of our analysis of ozone for areas with a 2012 attainment date, EPA proposes that we should not be constrained to only considering those reductions that are possible by 2012.

Another reason that it would be inappropriate to limit upwind state responsibility based on the downwind area's current attainment date is that the statute contains provisions for extension of attainment dates. To the extent that downwind states have continuing ozone air quality problems after 2012, the Act requires that they be reclassified, which allows the downwind area to qualify for a later attainment date that is as expeditious as practicable but no later than 2019 (2018 emissions year).[62] In addition, two 1-year attainment date extensions can be granted if an area comes close to attaining, based on specific criteria. In addition, history shows many examples of states not meeting air quality standards by their attainment deadlines, often due in part to interstate pollution transport. Even if a downwind area attains on time, further upwind reductions may be important to assure continued maintenance of the standard.

If in determining upwind state reduction responsibilities EPA were to automatically assume that downwind states will attain on time despite pollution transport, this assumption would have the effect of absolving the upwind state of responsibility for any reductions in pollution transport that could not be achieved by the downwind area's current attainment date. EPA does not believe this would be appropriate. This would transfer emissions control responsibility from the upwind state to the downwind state in any case when the area did not attain by its current attainment date, and could delay for years the date when the public would breathe air that meets health-based standards.

Accordingly, for all the reasons discussed previously, we address both 2012 and 2014 in our analysis, and we do not believe that examining 2012 only would be appropriate. EPA has chosen to examine 2014 air quality results because, based on a conservative estimate, 2014 is the earliest year for which significantly more stringent NO_X limits (e.g., reflecting SCR) could conceivably be considered in a swift, subsequent rulemaking.

One area in the eastern half of the U.S. covered by this proposal, Houston,

[61] This is possible where: (1) Latest monitoring data indicate attainment of the 1997 ozone standard, (2) the area is operating under one-year extensions of their 2009 deadline, or (3) EPA has not made a formal finding of failure to attain.

[62] In the case of $PM_{2.5}$, under subpart I, areas can qualify for an extension beyond 5 years, to as many as 10 years, based on certain statutory criteria.

is classified as "severe." For Houston, it is relevant to consider both that (1) the latest permissible attainment date for severe areas is June 2019, which would require emissions reductions by the 2018 ozone season, and (2) the state implementation plan must provide for attainment as expeditiously as practicable. In light of this, EPA may select a year between 2012 and 2018 that is as expeditious as practicable as the appropriate year for eliminating significant contribution. Because, as explained later, further analysis is needed to quantify any additional reductions necessary to eliminate significant contribution to Houston, EPA requests comment on which year we should select within this 2012 to 2018 time period for this analysis.

(2) Step 1. Emissions Reductions Cost Curves for EGU Ozone Season NO_X

Using IPM, EPA developed cost curves for 2012 for ozone season NO_X, showing the ozone season (May–September) NO_X reductions available in 2012 at different cost increments. Specifically, EPA developed cost curves that show reductions available in 2012 from EGUs at various costs (in 2006 $) up to $5,000/ton. These EGU cost curves are presented in Table IV.D–7. Generally, projected emissions reductions for 2012 are modest because, by 2012, it is not feasible to install add-on equipment. Some highly effective and widely employed NO_X control technologies such as SCR could not be planned and installed in significant numbers within a 1-year time period (i.e., because a single SCR unit on average takes 21 months to install,[63] SCR-based limits in 2012, if feasible at all, would require an unacceptably steep cost premium).

For some states (particularly those which are not regulated by the NO_X SIP Call) EPA identified potential reductions from the installation of some combustion controls/low NO_X burners and the use of existing SCR units that, in the absence of CAIR, would not be required to operate. These reductions are available at approximately $500/ton in 2012. There were very few emissions reductions available below this cost.

TABLE IV.D–7—2012 OZONE-SEASON NO_X EMISSIONS FROM ELECTRIC GENERATING UNITS FOR EACH STATE AT VARIOUS COSTS (2006$) PER TON (THOUSAND TONS)

Marginal cost per ton	$0	$500	$1,000	$1,500	$2,000	$2,500	$3,000	$3,500	$5,000
Alabama	30	30	30	30	30	30	30	29	29
Arkansas	21	11	11	11	11	11	11	11	11
Connecticut	3	3	3	3	3	3	3	3	3
Delaware	2	2	2	2	2	2	2	2	2
Florida	101	74	60	59	59	59	59	58	57
Georgia	35	33	33	33	33	33	33	33	33
Illinois	24	24	25	25	25	25	25	25	25
Indiana	51	50	49	48	47	47	47	46	46
Kansas	31	15	15	15	14	14	14	14	14
Kentucky	31	31	30	30	30	30	29	29	29
Louisiana	22	17	17	17	17	17	17	17	17
Maryland	14	14	14	14	14	14	14	14	14
Michigan	30	30	30	30	30	30	29	28	28
Mississippi	17	8	8	8	8	8	8	8	8
New Jersey	7	7	7	7	7	7	7	7	7
New York	16	16	16	16	16	16	16	16	16
North Carolina	27	27	27	27	27	27	27	27	27
Ohio	42	41	41	41	41	42	42	42	42
Oklahoma	43	27	27	27	27	26	26	26	26
Pennsylvania	51	51	51	51	50	50	50	50	48
South Carolina	16	16	16	15	15	15	15	15	15
Tennessee	12	12	12	12	12	12	12	12	12
Texas	79	67	67	67	7	66	66	66	66
Virginia	18	18	18	18	18	18	17	17	17
West Virginia	24	24	23	23	22	23	22	22	18
Total	746	648	632	628	625	622	620	618	609

As discussed in section IV.D.3 later, little or no ozone season NO_X reductions are available for non-EGU sources from control measures costing (at or below) $500/ton. The ozone season NO_X cost curves in Table IV.D–7 include EGU reductions only. EPA believes that for costs at or below $500/ton, these curves include all available reductions (because only EGUs have substantial reduction opportunities at or below $500/ton), but for greater costs the curves do not include all available reductions as they do not include non-EGU reductions.

For this reason, we are not addressing in this proposal whether cost per ton levels higher than $500/ton are justified for some upwind states and downwind receptors for ozone purposes. However, we are presenting the information we have on potential EGU reductions at higher cost levels for informational purposes. EPA intends to develop similar emissions reductions and cost information for sources other than EGUs and, in a future rulemaking, to consider whether or not reductions at a higher cost per ton are warranted for EGUs and other source categories.

EPA developed EGU emissions reductions cost curves for 2014 as well as 2012. EPA believes it is useful to understand and display emissions reductions capabilities for 2014, the first year for which further emissions reductions could be achieved through the installation of add-on controls such as SCR. These 2014 ozone season

[63] Estimate from EPA report, "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multi-Pollutant Strategies," CAIR docket no. OAR–2003–0053–0106).

emissions cost curves are presented in Table IV.D–8. The 2014 results have similarities to the 2012 results in that there is an initial drop in emissions when controls are applied at costs of $500 per ton, which represents the use of SCR units in states that would not be mandated to so. Also similar to the 2012 results, relatively few reductions are seen between $500/ton and $2,500/ton. In contrast to the 2012 results, add-on controls become feasible in 2014 at costs between $2,500/ton and $5,000/ton and more EGU emissions reductions are possible at those cost levels.

TABLE IV.D–8—2014 OZONE-SEASON NO_X EMISSIONS FROM ELECTRIC GENERATING UNITS FOR EACH STATE AT VARIOUS COSTS (2006$) PER TON (THOUSAND TONS)

Marginal cost per ton	$0	$500	$1,000	$1,500	$2,000	$2,500	$3,000	$3,500	$5,000
Alabama	27	27	27	27	27	27	27	26	26
Arkansas	22	12	12	12	12	11	11	11	12
Connecticut	3	3	3	3	3	3	3	3	3
Delaware	2	3	3	3	3	3	3	3	3
Florida	95	72	58	57	57	56	53	43	37
Georgia	22	20	20	20	20	20	20	20	19
Illinois	24	24	24	24	24	24	24	24	24
Indiana	49	48	48	47	47	47	46	44	43
Kansas	35	16	16	16	16	16	16	15	15
Kentucky	30	30	30	29	29	29	29	29	28
Louisiana	21	17	17	17	17	17	17	13	13
Maryland	15	15	15	15	15	15	15	15	15
Michigan	30	30	30	30	29	29	29	29	28
Mississippi	17	8	8	8	8	8	8	8	7
New Jersey	10	10	10	10	10	10	10	10	9
New York	17	17	17	16	16	16	15	15	15
North Carolina	27	27	27	27	27	27	27	27	26
Ohio	45	44	43	43	42	42	42	41	38
Oklahoma	39	24	24	24	24	23	23	23	20
Pennsylvania	53	53	52	52	52	52	52	52	41
South Carolina	16	16	15	15	15	15	15	15	15
Tennessee	12	12	12	12	12	12	12	12	12
Texas	80	69	68	68	67	66	66	66	66
Virginia	16	16	16	16	16	16	16	16	15
West Virginia	24	24	24	21	22	20	20	19	19
Total	732	639	621	614	610	604	598	579	547

(3) Step 2. Air Quality Assessment of Potential 2012 Emissions Reductions

EPA uses an air quality assessment tool for ozone to assess the effect of NO_X reductions on downwind ozone concentrations. This air quality assessment tool assumes a linear relationship between the reduction in an upwind state's ozone season NO_X reductions and the reduction in that state's contribution to downwind ozone levels. For example, if a given upwind state reduced its ozone season NO_X emissions by 20 percent, the air quality assessment tool estimates that there would also be a 20 percent reduction in the state's contribution to downwind ozone. Using this assessment tool, EPA projected the air quality impact of the emissions reductions at the $500/ton NO_X level, the level for which we have complete estimates of potential emissions reductions. The assessment shows significant improvements in 2012 at downwind air quality locations, as evidenced by a reduction in the number of nonattainment and maintenance locations. EPA presents these 2012 ozone season results in Table IV.D–9.

EPA also includes in Table IV.D–9 results for 2014 before and after the imposition of currently installed controls (that is, for the base case or zero dollars per ton, and for the case for which all controls are applied up to $500/ton). Because there are substantial reductions in ozone season NO_X from mobile source fleet turnover between 2012 and 2014, there are correspondingly substantial improvements in ozone in the base case, even in the absence of additional EGU or other stationary source controls. Additionally, in this 2014 analysis, when these mobile source reductions are combined with EGU reductions at $500/ton, the simplified air quality assessment tool projects that almost all sites, with the exception of Houston, TX (nonattainment) and Baton Rouge, LA (maintenance), have resolved their ozone problems.

TABLE IV.D–9—ESTIMATED NUMBER OF REMAINING NONATTAINMENT OR NONATTAINMENT AND MAINTENANCE MONITOR SITES IN 2012 AND 2014 AS A FUNCTION OF OZONE-SEASON NO_X COST PER TON LEVELS

	2012	2012	2014	2014
Marginal Cost per Ton	Number of Remaining Nonattainment Monitor Sites	Number of Remaining Nonattainment and Maintenance Monitor Sites	Number of Remaining Nonattainment Monitor Sites	Number of Remaining Nonattainment and Maintenance Monitor sites
>$0	11	25	4 (all in Houston, TX)	7 (Houston, TX; Baton Rouge, LA).
>$500	10	19	1	7.

(4) Step 3. Selection of Cost Thresholds, Taking Into Account Cost and Air Quality Considerations

Using the multi-factor cost and air quality methodology described in section IV.D.1, EPA identifies, for a number of states, the 2012 emissions reductions that eliminate the significant contribution to nonattainment of the 1997 ozone NAAQS and interference with maintenance to the 1997 ozone NAAQS.

(a) Cost Considerations

As discussed previously, $500/ton represents the cost level for which EPA has complete information across source categories and represents the level for which significant emissions reductions are available in 2012. Large additional reductions in 2012 cannot be achieved given the insufficient amount of time for sources to install controls. Compared to NO_X reduction levels determined to be highly cost effective in both the NO_X SIP Call and the CAIR, $500/ton is a very low cost for requiring ozone season NO_X reductions, and reductions at this level show measurable downwind air quality benefit. EPA believes that $500/ton continues to be an extremely cost effective level for NO_X control relative to benchmarks provided by the cost per ton of NO_X reductions in existing rules or available from technologies in various sectors, and the $500/ton level is based on proven and widely deployed technology.

Considering the upwind-downwind state policy considerations discussed previously, $500/ton NO_X clearly is not an unreasonable cost level of control for all upwind states that contribute more than threshold amounts to ozone air quality problems in downwind states.

EPA believes that on purely reasonableness or highly cost effective grounds, a value considerably greater than $500/ton could be justified. EPA notes that the $2,000/ton threshold for highly cost effective ozone season NO_X controls for the NO_X SIP Call was calculated based on 1990 dollars. If this threshold were updated based on a more recent year, such as the 2006 year used for recent EPA RIA documents, the $2,000/ton threshold would become approximately $3,200 per ton. As a result, EPA believes that controlling to at least this level should be considered, unless air quality considerations suggest an "off-ramp" at lower cost levels.

(b) Air Quality Considerations

Using the air quality assessment tool, EPA determined that emissions reductions from ozone season NO_X controls at $500/ton would have a significant reduction in nonattainment and maintenance receptors in 2012. Accordingly, EPA believes that requiring the reductions that can be achieved at $500/ton are justified based upon the 2012 air quality results.

EPA proposes, as discussed previously, that EPA is not artificially constrained in considering reductions beyond 2012 and that it is relevant to address possible air quality impacts of additional emissions reductions that could be achieved by 2014, the first year for significant additional controls. At the same time, EPA proposes that while 2014 is a relevant year to consider, it is also relevant to consider the nature of the air quality problem in 2014 even in the absence of further transport controls that could be achieved by that date. Taking all of these 2014 considerations into account, the air quality assessment tool results show that in 2014 ozone problems remain only for locations in Houston and Baton Rouge. Thus, EPA believes that additional post-2012 controls, beyond the $500/ton reductions that are justified based on 2012, are possibly warranted for states that are linked to Houston and Baton Rouge. (See also discussion later on the issue regarding New York City raised by air quality modeling results.)

(c) Proposed Cost Threshold for Ozone

Based on the cost and air quality considerations, EPA proposes $500/ton as the appropriate cost threshold for the following states which contribute to downwind nonattainment and/or maintenance problems in 2012, but which are not linked to ozone air quality problems in either Houston or Baton Rouge: Connecticut, Delaware, the District of Columbia, Indiana, Iowa, Kansas, Maryland, Massachusetts, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Virginia, and West Virginia.

For states linked to ozone air quality problems in Houston or Baton Rouge, EPA has not yet identified a cost threshold for eliminating significant contribution. EPA does, however, propose to find that those states must make at least all of the reductions that can be achieved for $500/ton in 2012. These states are: Alabama, Arkansas, Florida, Georgia, Illinois, Kentucky, Louisiana, Mississippi, Tennessee, and Texas. For these states, the $500/ton threshold represents emissions reductions that EPA believes are an essential part of the ultimate emissions reductions amount that will be required to eliminate the significant contribution and interference with maintenance. This level does not represent a complete significant contribution determination for these states because neither the analysis of costs up to $500/ton, nor the analysis of air quality impacts of the corresponding emissions reductions, suggest that those reductions necessarily represent all reasonable upwind state reductions. For the reasons stated previously in subsection 2.b, EPA believes it is appropriate and consistent with the statutory mandate to consider whether section 110(a)(2)(D)(i)(I) requires further reductions from these states after 2012 for purposes of the 1997 ozone standard.

To determine whether further reductions are warranted, EPA is expeditiously conducting further analysis. EPA is continuing to develop and evaluate NO_X control costs, emissions reductions, and air quality impact information for NO_X controls greater than $500/ton, and to examine facts involving Houston and Baton Rouge, to support a complete determination of significant contribution and interference with maintenance for states that contribute to one or both of those areas. Based on the analysis done for today's proposal, EPA believes that any additional NO_X reduction requirements would involve reductions from sources beyond EGUs. If this is the case, EPA believes it is likely that we could provide the greatest assistance to states in addressing transport by promulgating a separate rule to achieve those NO_X reductions. EPA believes that developing supplemental information to address these sources beyond EGUs would substantially delay publication of a final rule, beyond the anticipated publication of spring 2011. While EPA intends to move forward aggressively on this issue in gathering the necessary information, EPA does not believe that this effort should delay the reductions and large health benefits associated with this proposed rule. EPA fully intends to proceed with additional rulemaking to fully address the residual significant contribution to nonattainment and interference with maintenance as quickly as possible.

(5) Request for Comment Concerning New York City and Contributing States

As in the case of $PM_{2.5}$, EPA has done additional refined air quality analysis of a 2014 scenario that assumes implementation of the proposed ozone season NO_X emissions reductions, that is, the reductions that would be achieved based on the $500/ton NO_X cost threshold. This air quality analysis, conducted with the CAMx model, can be compared to the results using the air quality assessment tool. The CAMx modeling demonstrated that the required NO_X reductions would assist many downwind areas with achieving and maintaining the NAAQS. The CAMx air quality modeling for 2014 confirmed the conclusion that Houston and Baton Rouge would continue to have nonattainment/maintenance concerns even with the reduction of NO_X emissions that could be reduced for (at or below) $500/ton. The modeling also showed that the locations within the New York City nonattainment area would continue to have a maintenance problem despite the modeled reductions (including those in New York State). That is, the New York City area is possibly at risk of being in nonattainment in light of historical year-to-year variability in ozone levels in the New York City area. For that reason, EPA is taking comment on whether it should consider and analyze the NO_X reductions that can be achieved for greater than $500/ton in states that are linked to the New York area sites. These states include: Connecticut, Delaware, Indiana, Kentucky, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia, and West Virginia. If EPA were to conclude that additional analysis is necessary, it would present the results of this in a future notice that would also consider whether and to what extent states linked to New York City, Houston, and Baton Rouge should be required to make additional NO_X reductions in order to eliminate all significant contribution with respect to the 1997 ozone NAAQS.

3. Discussion of Control Costs for Sources Other Than EGUs

Previously in this section (see discussion in IV.D.2 previously) EPA discusses its proposed cost criteria for identifying SO_2 and NO_X emissions reductions necessary to eliminate at least part of each state's significant contribution and to eliminate at least part of each upwind state's interference with maintenance of the $PM_{2.5}$ NAAQS. In addition, EPA discusses interim cost criteria for ozone. Consistent with these criteria, EPA does not believe that other source categories have emissions that are currently significantly contributing to nonattainment or interfering with maintenance of the 1997 and 2006 $PM_{2.5}$ NAAQS. Thus, with respect to the 1997 and 2006 $PM_{2.5}$ NAAQS, we are not proposing to include in the FIPs emissions reductions requirements for other source categories.

(a) SO_2 Sources and Costs

As described previously, EPA is proposing to define significant contribution on the basis of cost informed by air quality impacts, and to conclude $2,000/ton represents the highest cost value necessary for SO_2 to eliminate significant contribution and interference with maintenance. For SO_2, as described previously, EPA is proposing to conclude that significant contribution and interference with maintenance would be eliminated at costs of no more than $2,000/ton, and in some states, at lower costs. The EPA has not identified SO_2 reductions for sources other than EGUs at $2,000/ton or less (in year 2006 $).

For the CAIR, EPA included a technical support document [64] which noted that for SO_2, EGUs were the dominant contributor to transported emissions, but that there were a few additional categories for which regional emissions exceeded 1 percent of the overall inventory in the eastern half of the U.S. EPA has updated this analysis with a review of the year 2012 inventory, with similar conclusions. *See* TSD—"Non-EGU Emissions Reductions Cost and Potential." The highest-emitting categories of non-EGU SO_2 emissions are: (1) Industrial, commercial, and institutional (ICI) boilers, (2) Portland cement manufacturing, (3) petroleum refining, and (4) sulfuric acid manufacturing.

For ICI boilers, most of the SO_2 emissions are from coal-fired boilers, and to a lesser degree from residual or distillate oil-fired boilers. Possible ways to reduce SO_2 emissions from ICI boilers include fuel switching, flue gas desulfurization, and dry sorbent duct injection. Because of variability in operations, it is difficult to identify precise cost per ton estimates for fuel switching and sorbent injection. For industrial boilers, the capacity factor (that is, the fraction of boiler capacity that is used in a year) can have a significant impact on the cost per ton estimate. Regarding flue gas desulfurization, a recent report prepared by NESCAUM [65] suggests scrubber costs are typically well above $2,000/ton for ICI boilers.

For Portland cement manufacturing, information from a 2006 report prepared by the Lake Michigan Air Directors Consortium (LADCO) estimated costs for SO_2 scrubbing to be between $2,211–6,917 per ton (in year 2003 $). The LADCO "white papers" discussion is available from the following Web site: *http://www.ladco.org/reports/control/final_reports/identification_and_evaluation_of_candidate_control_measures_ii_june_2006.pdf.*

For petroleum refining, the largest sources of SO_2 emissions are from catalytic cracking, sulfur recovery units, and process heaters. For each of the sources in the petroleum refining sector, EPA believes that SO_2 controls at or below $2,000/ton will generally not be available at refineries covered by the recent settlement agreements EPA has entered into with numerous petroleum refineries. Moreover, such agreements cover 88 percent of U.S refining capacity, and will lead to up to 250,000 tons of SO_2 emissions reductions annually. Compliance with these agreements has already taken place at most affected refineries, and these reductions are generally reflected in our 2012 base case emissions inventory.[66]

For sulfuric acid manufacturing, the SO_2 emissions are related to the percent recovery of sulfuric acid product. Because the percent recovery is plant-specific, the available emissions reductions and the cost per ton of controls are highly variable. At the time of the CAIR, EPA made rough calculations that the then-existing 126,000 tons of SO_2 would be reduced by about one-half if all of the sulfuric acid manufacturing in the eastern U.S. was controlled to meet the NSPS level of 4 pounds of SO_2 per ton of product. EPA did not develop cost estimates for these approximate reductions and such cost estimates are still not available. EPA notes, however, that it has entered into a number of settlement agreements with sources in the sulfuric acid production industry, and a significant amount of the estimated available reductions has already been realized. Over 36,000 tons of SO_2 reductions have taken place at 22 plants in the U.S. by 2012 as a result of 6 settlement agreements.[67] More than half of these plants are in states affected by this proposal.

This information shows that few if any SO_2 reductions are available from other source categories and thus, along with other information available to EPA, supports EPA's proposal not to include non-EGU SO_2 reduction requirements for addressing $PM_{2.5}$ transport for the proposed rule. EPA seeks comment on whether non-EGU emissions reductions should be required and on the specific

[64] Identification and Discussion of Sources of Regional Point Source NO_X and SO_2 emissions other than EGUs. EPA/OAQPS and CAMD. January 2004.

[65] Reference: NESCAUM Applicability and Feasibility of NO_X, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers. NESCAUM, November 2008. pp. xvii, 3–12–13.

[66] U.S. EPA. Petroleum Refinery National Priority Case Results. Available at *http://www.epa.gov/compliance/resources/cases/civil/caa/oil/index.html.*

[67] U.S. EPA. Acid Plant NSR Enforcement Priority. Available at *http://www.epa.gov/compliance/civil/caa/acidplant-nsr/index.html.*

control measures that would serve as the basis for those reductions.

Because sulfur content of both gasoline and diesel fuel are now subject to very stringent sulfur requirements, EPA believes there are no available on-road and nonroad engine measures to reduce mobile source SO_2 at or below $2,000/ton.

b. NO_X From Non-EGU Sources

For NO_X, the methodology described previously in section IV.D.2 requires all states linked to $PM_{2.5}$ nonattainment and maintenance areas to ensure that emissions do not increase above 2009 levels. This translates into a cost cutoff of $500/ton. In addition, for ozone, EPA determined that a number of states can eliminate their significant contribution and interference with maintenance by installing controls at this same $500/ton cost threshold.

For the CAIR, the technical support document [68] evaluating non-EGU controls contained a discussion of non-EGU category contributions to the overall NO_X emissions inventory and a discussion of available controls. This analysis identified source categories for which regional emissions exceeded 1 percent of the overall inventory in the eastern half of the U.S. EPA has updated this analysis of non-EGU NO_X controls done for the CAIR with a review of the year 2012 inventory. *See* TSD—"Non-EGU Emissions Reductions Cost and Potential." The highest-emitting stationary source categories of non-EGU NO_X emissions are: (1) Stationary reciprocating internal combustion engines (RICE), (2) industrial, commercial, and institutional (ICI) boilers, (3) Portland cement manufacturing, (4) petroleum refining, (5) glass manufacturing, (6) pulp and paper production, and (7) iron and steel production.

EPA has not identified additional non-EGU controls that can be achieved at $500/ton or less. For example, available information [69] suggests that costs of various types of NO_X controls are greater than this level for non-EGU sources such as ICI boilers, iron and steel mills, petroleum refineries, [70] glass manufacturing plants, and asphalt manufacturing plants. For industrial boilers, a recent report prepared by NESCAUM [71] suggests NO_X control costs are typically well above $500/ton for ICI boilers. In addition, a recent report prepared by LADCO [72] indicated NO_X control costs are also well above $500/ton for glass manufacturing plants and asphalt manufacturing plants.

For the NO_X SIP Call, EPA identified a number of categories where costs were less than $2,000/ton (1990 dollars), including large ICI boilers with capacities greater than 250 million BTU/hour, cement kilns, and large RICE emitting more than 1 ton NO_X per day. For each of these categories regulated under the NO_X SIP Call, EPA believes there are no available control measures (especially that could be implemented by 2012) at or below $500/ton.

EPA has not identified further controls for stationary nonpoint sources or mobile source NO_X measures that have costs at or below $500 per ton.

E. State Emissions Budgets

As described later, EPA used the cost thresholds identified for each covered state in the previous section and applied them to state-specific data to develop individual state emissions budgets. These budgets facilitate implementation of the requirement that significant contribution and interference with maintenance be eliminated. A state's emissions budget is the quantity of emissions that would remain in that state from covered sources after elimination of that portion of each state's significant contribution and interference with maintenance that EPA has identified in today's proposal, before accounting for the inherent variability in power system operations (*see* discussion of variability in section IV.F, later). The state emissions budget is a mechanism for converting the quantity of emissions that a state must reduce (*i.e.*, the state's significant contribution and interference with maintenance) into enforceable control requirements. In other words, it provides a quantity of emissions to use in developing a remedy (*e.g.*, the remedy should be designed to achieve the budget in an average year).

Because the budget represents emissions that would remain without accounting for variability, it also represents the amount of emissions that would remain after significant contribution and interference with maintenance have been addressed, in an average year. In a year when base case emissions would have been higher than average (*e.g.*, because a large nuclear unit was out of service and more fossil-fuel-fired generation was needed), the emissions that would remain after significant contribution and interference with maintenance had been addressed also would be higher. The variability limits discussed in section IV.F address this issue. Application of variability limits in the remedies is described in section V.D.

1. Defining SO_2 and Annual NO_X State Emissions Budgets for EGUs

For group 1 states required to make deeper emissions reductions in 2014, EPA based each state's 2014 budgets on the same projections from IPM that were used as inputs into the cost curves explained in section IV.D.2.a previously. For SO_2, the values were taken from an IPM run requiring all SO_2 reductions available at $2,000/ton. For group 2 states (and for the first phase 2012 budgets for sources required to make greater reductions in 2014), EPA took a different approach. These states are only required to make SO_2 reductions that could be made through (1) the operation of existing scrubbers, (2) scrubbers that are expected to be built by 2012 and (3) the use of low sulfur coal. Because those strategies were already being applied in most states covered by this rule in 2009, [73] EPA believes that the actual performance units achieved in 2009 is more representative of expected emissions than what EPA modeled using IPM. This is because real data takes into account actual unit by unit information that is represented at a more aggregate level in IPM. The only exception to this rule is if a source was modeled to install a scrubber by 2012 (because of rules requiring that installation and/or because of information that the company had already contracted to install a scrubber). In this case, EPA adjusted emissions from the unit to account for the new scrubber.

For 2012 NO_X budgets, EPA used the same general methodology for all states that was used for the group 2 states for SO_2. The $500/ton cost threshold, that EPA has determined can be used to calculate the minimum significant contribution from upwind states linked to downwind nonattainment and maintenance areas, almost exclusively

[68] Identification and Discussion of Sources of Regional Point Source NO_X and SO_2 emissions other than EGUs. EPA/OAQPS and CAMD. January 2004.

[69] Reference: Identification and Evaluation of Candidate Control Measures. Phase II Final Report. LADCO, June. 2006. Appendix B.

[70] Reference: Assessment of Control Technology Options For Petroleum Refineries in the Mid-Atlantic Region. Final Report. MARAMA, January 2007. p. 2–24.

[71] Reference: NESCAUM Applicability and Feasibility of NO_X, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers. NESCAUM, November 2008. pp. xvii, 3–12–13.

[72] Reference: Identification and Evaluation of Candidate Control Measures. Phase II Final Report. LADCO, June 2006. Appendix B.

[73] Even though allowance prices dropped significantly in 2008 after the Court decision, most sources appear to have continued with the same reduction strategies.

represents reductions from turning on SCR units. EPA believes that instead of defining the budgets based on IPM projections of what will happen when SCR units are turned on, it is better to use real data, therefore EPA has developed budgets based on a combination of historical heat input, historical emissions rates, and, where new SCR units are expected between now and 2012, projected emissions rates for those new SCR units. The emissions budgets developed using the previous methodology are as follows in Table IV.E–1:

TABLE IV.E–1—SO_2 AND ANNUAL NO_X STATE EMISSIONS BUDGETS FOR ELECTRIC GENERATING UNITS BEFORE ACCOUNTING FOR VARIABILITY [74]

[Tons]

State	SO_2, 2012 and 2013	SO_2, 2014 and later	NO_X annual, all years
Alabama	161,871	161,871	69,169
Connecticut	3,059	3,059	2,775
Delaware	7,784	7,784	6,206
District of Columbia	337	337	170
Florida	161,739	161,739	120,001
Georgia	233,260	85,717	73,801
Illinois	208,957	151,530	56,040
Indiana	400,378	201,412	115,687
Iowa	94,052	86,088	46,068
Kansas	57,275	57,275	51,321
Kentucky	219,549	113,844	74,117
Louisiana	90,477	90,477	43,946
Maryland	39,665	39,665	17,044
Massachusetts	7,902	7,902	5,960
Michigan	251,337	155,675	64,932
Minnesota	47,101	47,101	41,322
Missouri	203,689	158,764	57,681
Nebraska	71,598	71,598	43,228
New Jersey	11,291	11,291	11,826
New York	66,542	42,041	23,341
North Carolina	111,485	81,859	51,800
Ohio	464,964	178,307	97,313
Pennsylvania	388,612	141,693	113,903
South Carolina	116,483	116,483	33,882
Tennessee	100,007	100,007	28,362
Virginia	72,595	40,785	29,581
West Virginia	205,422	119,016	51,990
Wisconsin	96,439	66,683	44,846
Total	3,893,870	2,500,003	1,376,312

For more detail on how the budgets were developed, *see* the TSD: "State Budgets, Unit Allocations, and Unit Emissions Rates".

2. Defining Ozone Season NO_X State Emissions Budgets for EGUs

Ozone season NO_X budgets were developed the same way as the annual NO_X budgets were developed (explained in IV.E.1, previously).

TABLE IV.E–2—OZONE-SEASON NO_X STATE EMISSIONS BUDGETS FOR ELECTRIC GENERATING UNITS BEFORE ACCOUNTING FOR VARIABILITY

[Tons]

State	NO_X ozone season, all years
Alabama	29,738
Arkansas	16,660
Connecticut	1,315
Delaware	2,450
District of Columbia	105
Florida	56,939
Georgia	32,144
Illinois	23,570
Indiana	49,987
Kansas	21,433
Kentucky	30,908
Louisiana	21,220
Maryland	7,232
Michigan	28,253
Mississippi	16,530
New Jersey	5,269
New York	11,090
North Carolina	23,539
Ohio	40,661
Oklahoma	37,087
Pennsylvania	48,271
South Carolina	15,222
Tennessee	11,575
Texas	75,574
Virginia	12,608
West Virginia	22,234
Total	641,614

[74] The impact of variability on the budgets is discussed in section IV.F, later.

These budgets are based on a 5 month ozone season (May 1 through September 30). Consistent with the approach taken by the OTAG, the NO_X SIP Call, and the CAIR, we propose to define the ozone season, for purposes of emissions reductions requirements in this rule, as May through September. We recognize that this ozone season for regulatory requirements will have differences from the official state-specific ozone monitoring season. EPA requests comment on whether the budgets for the final rule should be based on a longer ozone season, such as March through October.

F. Emission Reduction Requirements Including Variability

In this section, EPA discusses the inherent variability in electric power system operation and presents proposed variability limits for each state. As explained below, EPA proposes to calculate variability limits for each state and to use those variability limits in conjunction with the budgets (which are based on expected average conditions) to provide limited flexibility (within the limits allowed by the variability provisions) to address years in which more fossil generation occurs than projected in the average base case year. This section also presents projected emission reduction results.

1. Variability

a. Introduction to Power Sector Variability

Historically, power sector emissions have varied over time. Factors, such as fuel switching and installing new emissions controls, which can lead to significant decreases in emissions, primarily affect emissions rates rather than generation and change largely as a result of pollution regulation.

Even when emissions rates do not change from year to year, overall emissions can change because of factors including power demand, timing of maintenance activities, and unexpected shutdowns of units. Extreme weather conditions, sudden economic shocks, and other unpredictable events can also significantly impact power generation from fossil units. These factors relate directly to heat input, generation, and the routine operation of power plants to supply our electricity, and thus affect total emissions.

As discussed previously, EPA has identified a specific amount of emissions that must be prohibited by each state to satisfy the requirements of CAA section 110(a)(2)(D)(i)(I). EPA has also developed state budgets based on its projections of state emissions in an average year after the elimination of such emissions. However, because of the unavoidable variability in baseline emissions—resulting from the inherent variability in power plant operations—state-level emissions may vary somewhat after all significant contribution and interference with maintenance that EPA has identified in this proposal are eliminated. This occurs even when the emissions rates of the units within the state do not change. For this reason, EPA has determined that it is appropriate to develop variability limits for each state budget. These limits are used to identify the range of emissions that EPA believes may occur in each state following the elimination of all significant contribution and interference with maintenance.

For the proposed rule, EPA proposes to factor this variability explicitly in its consideration of how to control emissions. The Agency believes that because baseline emissions are variable, emissions after the elimination of all significant contribution are also variable and thus it is appropriate to take this variability into account.

As discussed in detail in section V, EPA proposes and considers specific regulatory remedies that are designed to meet the emissions budget in an average year. Because base case emissions may vary from projections, EPA believes these same remedies may incorporate provisions that account for variability. This variability, however, must be limited to provide downwind states with assurance that necessary reductions will be made in upwind states. This section describes how EPA calculated variability limits for each state to achieve this goal.

Remedies (*i.e.*, regulatory approaches for achieving emissions reductions) can range from emissions rate-based "direct control" options to options which allow for interstate trading. EPA believes that inherent variability in power system operations affects each state's baseline emissions and thus also affects a state's emissions after elimination of all significant contribution and interference with maintenance. Thus, emissions may vary somewhat after implementation of the remedies under consideration. Under an emissions rate-based approach, emissions rate limits could be developed that would meet the budget assuming a given pattern of operation for the affected units. If some of the units with higher emissions rates actually operated more than projected, the state's actual emissions would be higher. In an interstate trading program, budgets could be developed that each state would be projected to meet in an average year. In some years, however, generation from units in one state may increase (with a corresponding increase in emissions), but because variability in a larger region is less significant than within a single state, the increase in one state would be expected to be offset by decreases in other states. Finally, even in an intrastate-only trading program, the ability to bank allowances could mean that in one year, emissions would be below the budget, while in another year they would be above.

In all these cases, variability limits can be used to retain the flexibilities that the various remedies provide to deal with real-world variability in the operating system, while still providing downwind states reasonable certainty about the level of upwind emissions.

EPA also notes that explicit consideration of variability in the emissions resulting from a remedy is consistent with removing a state's "significant contribution." As noted previously, even if the emissions result is variable from year to year, there is still a similar increment of emissions reductions. For example, because increased emissions in the control case would also correspond to increased emissions in the base case, the increment of emissions representing significant contribution and interference with maintenance would still be removed. Finally, as is explained more below in IV.F.b, the variability limits (as applied, for instance, in the State Budgets/Limited Trading remedy in section V.D.4) are relatively low and thus the total amount of variability allowed is very small compared to total EGU emissions and even smaller when considering all of the emissions within a state. It is also worth noting that in the proposed State Budgets/Limited Trading remedy, variability is taken into account in such a way that does not allow an overall increase in emissions. Under this remedy, an individual state could emit up to its budget plus variability limit. However, the requirement that all sources hold allowances to cover emissions, and the fact that those allowances are allocated based on state-specific budgets absent variability, would ensure that total emissions do not increase. This remedy, therefore, ensures not only that total emissions do not increase above state budgets, but also that reductions occur in each and every state.

b. How EPA Accounted for Inherent Power Sector Variability

EPA determined 1-year variability limits and 3-year rolling average variability limits for each state. First, EPA determined 1-year variability limits based on historical variability in heat input. Second, EPA determined 3-year rolling average variability limits using statistical methods to convert the 1-year variability into 3-year variability. The approaches EPA used to determine the

1-year and 3-year limits are summarized later and described in more detail in the Power Sector Variability TSD.

Expected variability over a single year. EPA performed analyses using historical data to demonstrate that there is year-to-year variability in baseline emissions (even when emissions rates for all units are held constant) and to quantify the magnitude of this variability. This year-to-year variability in emissions is reflected, in combination with other factors, in year-to-year variability in air quality.

The focus of the analysis is on quantifying the magnitude of the inherent variability in the baseline emissions (on both a 1-year and a 3-year basis). The goals of this analysis, therefore, are to determine the typical variability in emissions that is due to changes in generation, and not due to changes in emission limits, and to set emissions criteria limits that can be used as part of a remedy to ensure that states are eliminating their significant contribution and interference with maintenance to protect air quality.

EPA used statewide average emissions rates projected using IPM to convert historical heat input variability into corresponding emissions variability limits. The approach assessed the variability in state-level heat input over a 7-year time period (2002 through 2008) using the standard deviation and then determined the difference in emissions from the 95th percent two-tailed confidence level and the mean.[75] The approach resulted in a maximum allowable variability, in tons, for each state. These values were then divided by the mean emissions values over the 7-year time period to yield a percentage variability value for each state. *See* the Power Sector Variability TSD for details.

From the state-by-state tonnage and percentage emission variability values, EPA identified a single set of variability levels (that is, a tonnage and a percentage) based on the historic variability. EPA made the decision to adopt a single, uniform tonnage and percentage level pairing to apply to all states in order to make the application of the variability limits straightforward rather than developing state-by-state percentage variability values. The effect of the pairing is to ensure that each state is allowed adequate variability while minimizing the total amount of emissions allowed. Using, for all states, only a constant percentage (reflecting emissions variability in smaller states with a greater range of emissions in percentage terms) would result in large states being allowed greater variability than needed. Conversely, using only a constant tonnage (reflecting emissions variability in larger states with a greater range of emissions in tonnage terms) would result in small states being allowed greater variability than needed. To ensure adequate variability limits—even in states with small numbers of units where expected variability would be more pronounced in percentage terms, and in large states where expected variability would be more pronounced in absolute tonnage terms—EPA derived variability limits both as a percentage and in terms of absolute emissions (tons) that serve to minimize the total amount of emissions allowed under this combination variability limit approach.

For the tonnage and percentage limit criteria, EPA looked at a wide range of percentage and tonnage combinations, and chose for further investigation combinations that provided states sufficient variability limits (based on historic variability) and fit the requirement of minimizing the allowed emissions. Power plants in states that were close to the variability limits were evaluated more closely to ensure the modeling reflected all controls known to operate. EPA believes that the chosen limits would not be tighter than these states could be expected to meet.

This approach (identifying both a tonnage and a percentage) addresses the difficulty that smaller states with fewer units could face if only percentages were used to set the limits. For instance, in a small state with a budget of 5,000 tons of SO_2, an infrequently used unit that on average emitted 500 tons when it operated 10 percent of the time could increase its emissions to 1,500 tons by operating 30 percent of the time in a year when there is unusually high demand for that unit. That would result in a 20 percent increase in statewide emissions. In a much larger state, with a budget of 50,000 tons, such a change in operation would only lead to a 1 percent change in statewide emissions.

For both annual NO_X and SO_2, the percentage variability limits are 10 percent of a state's budget and the corresponding tonnage variability limits are 5,000 and 1,700 tons for NO_X and SO_2, respectively. These are the values that result from the approach described previously, *i.e.*, these variability levels allow the necessary variability for every state based on its historic variability, while minimizing the amount of emissions allowed.

EPA assigned each state one of these values—either the tonnage limit or the percent limit, whichever was greater for that state. For instance, 10 percent of Connecticut's SO_2 budget is less than 1,700 tons, so Connecticut received a 1-year 1,700 ton variability limit for its EGU SO_2 emissions. EGU sources in Connecticut could emit up to the state's SO_2 budget plus the variability limit of an additional 1,700 tons of SO_2 in a year, and still eliminate the state's significant contribution and interference with maintenance. Proposed 1-year variability limits for each covered state are shown in the tables in section IV.F.2, later. See the Power Sector Variability TSD for more details on EPA's variability approach.

Expected variability over a 3-year time period. Because air quality is assessed under the Act annually on a rolling 3-year time period, EPA believes that it is appropriate to also evaluate the inherent variability in emissions over similar time periods, and to establish state budgets with variability limits that ensure that the significant contribution and interference with maintenance that EPA has identified in this notice be eliminated.

While the year-to-year variability in emissions could lead to variability in 3-year rolling averages, inherent variability is lower over a 3-year time period than over a 1-year period and thus a state's 3-year variability limit will be lower than the state's 1-year variability limit. Establishing such 3-year limits thus provides an opportunity to ensure that the variability limits do not allow greater fluctuation in emissions than justified based on historic variability. EPA estimated the variability in a state's emissions over a 3-year time period based on the expected variability in emissions for a single year.

As summarized later and described in the Power Sector Variability TSD, the Agency used statistical methods to estimate the 3-year variability based on 1-year variability. The average variability of a multi-year sample is the average variability of a single year divided by the square root of the number of years in the multi-year sample.[76] Thus, the variability of a 3-year average is equal to the annual variability divided by the square root of three. EPA used this approach to determine 3-year variability limits based on the 1-year limits. For example, the Agency calculated the 3-year variability that corresponds to a 1-year variability of 5,000 tons as 5,000 divided by the

[75] The two-tailed 95th percent confidence level is the equivalent of the 97.5th upper (single-tailed) confidence level.

[76] Moore, David S. and George P. McCabe. *Introduction to the Practice of Statistics.* 2nd ed. New York: W.H. Freeman and Company, 1993. p. 395.

square root of three, or 2,887 tons. Similarly, EPA calculated the 3-year variability that corresponds to a 1-year variability of 1,700 tons as 1,700 divided by the square root of three, or 981 tons. EPA decided to use three years instead of some other interval in order to be consistent with 3-year averaging used to assess attainment with the NAAQS, as explained earlier in this section.

Proposed 3-year variability limits for each covered state are shown in the tables in section IV.F.2, later. *See* the Power Sector Variability TSD for more details on EPA's variability approach.

2. State Budgets With Variability Limits

As explained previously, EPA determined variability limits for each state. EPA then applied these variability limits on a state-by-state basis to calculate state-specific emissions budgets with variability limits. EPA calculated state budgets with both 1-year and 3-year variability limits.

Table IV.F–1 shows proposed variability limits by state on SO_2 emissions for 2014 and later. Table IV.F–2 shows proposed variability limits by state on NO_X annual emissions for 2014 and later. EPA requests comment on the proposed variability limits.

EPA also requests comment on an alternative calculation method for variability. The alternative method would use the results of the proposed method but add a ceiling based on the maximum percentage of variability among covered states as observed in the historic heat input data described previously. For both NO_X annual and SO_2, the percentage limits calculated using this alternative methodology are 21 and 28 percent of a state's budget, respectively. Under this alternative calculation method, a state's variability limit would be no lower than 10 percent of its budget and no higher than 21 or 28 percent, for NO_X and SO_2, respectively. Because no state varied more than these percentages, EPA believes they could serve as reasonable caps on variability limits. These limits would address the issue of small states receiving very large variability limits as a fraction of their budgets.

For instance, although Connecticut's proposed 1-year variability limit of 1,700 tons is greater than 10 percent of its SO_2 budget of 3,059 tons (306 tons), it is also greater than 28 percent of the budget (857 tons). Therefore, under this alternative calculation method, Connecticut's 1-year SO_2 variability limit would be 857 tons (28 percent of the state's SO_2 budget). Similarly, for annual NO_X, while Connecticut's proposed 1-year variability limit of 5,000 tons is greater than 10 percent of its NO_X annual budget of 2,775 (278 tons), it is greater than 21 percent of the budget (583 tons). Therefore, under this alternative approach, Connecticut's 1-year annual NO_X variability limit would be 583 tons. Tables IV.F–1 through IV.F–3 show the variability limits under the proposed and alternative calculation methods. *See* the Power Sector Variability TSD in the docket for this rule for more details.

TABLE IV.F–1—VARIABILITY LIMITS ON SO_2 ANNUAL EMISSIONS FOR 2014 AND LATER FOR ELECTRIC GENERATING UNITS

[Tons]

State	SO_2 annual emissions budget	Proposed		Alternative	
		1-year limit	3-year average limit	1-year limit	3-year average limit
Alabama	161,871	16,187	9,346	16,187	9,346
Connecticut	3,059	1,700	981	857	495
Delaware	7,784	1,700	981	1,700	981
District of Columbia	337	1,700	981	94	54
Florida	161,739	16,174	9,338	16,174	9,338
Georgia	85,717	8,572	4,949	8,572	4,949
Illinois	151,530	15,153	8,749	15,153	8,749
Indiana	201,412	20,141	11,629	20,141	11,629
Iowa	86,088	8,609	4,970	8,609	4,970
Kansas	57,275	5,728	3,307	5,728	3,307
Kentucky	113,844	11,384	6,573	11,384	6,573
Louisiana	90,477	9,048	5,224	9,048	5,224
Maryland	39,665	3,967	2,290	3,967	2,290
Massachusetts	7,902	1,700	981	1,700	981
Michigan	155,675	15,568	8,988	15,568	8,988
Minnesota	47,101	4,710	2,719	4,710	2,719
Missouri	158,764	15,876	9,166	15,876	9,166
Nebraska	71,598	7,160	4,134	7,160	4,134
New Jersey	11,291	1,700	981	1,700	981
New York	42,041	4,204	2,427	4,204	2,427
North Carolina	81,859	8,186	4,726	8,186	4,726
Ohio	178,307	17,831	10,295	17,831	10,295
Pennsylvania	141,693	14,169	8,181	14,169	8,181
South Carolina	116,483	11,648	6,725	11,648	6,725
Tennessee	100,007	10,001	5,774	10,001	5,774
Virginia	40,785	4,079	2,355	4,079	2,355
West Virginia	119,016	11,902	6,871	11,902	6,871
Wisconsin	66,683	6,668	3,850	6,668	3,850
Total	2,500,003				

Proposed 1-year variability limits are the larger of (1) 1,700 tons or (2) 10 percent of the state's budget. 3-year limits are the 1-year limits divided by the square root of three.

The alternative 1-year variability limit is 1,700 tons as long as that amount is between 10 and 28 percent of the state's budget. If 1,700 tons is greater than 28 percent of the state's budget, the state's limit is set at 28 percent of its budget. If 1,700 tons is less than 10 percent of the state's budget, the state's limit is set at 10 percent of its budget.

TABLE IV.F–2—VARIABILITY LIMITS ON NO_X ANNUAL EMISSIONS FOR 2014 AND LATER FOR ELECTRIC GENERATING UNITS

[Tons]

State	NO_X annual	Proposed		Alternative	
		1-year limit	3-year average limit	1-year limit	3-year average limit
Alabama	69,169	6,917	3,993	6,917	3,993
Connecticut	2,775	5,000	2,887	583	336
Delaware	6,206	5,000	2,887	1,303	752
District of Columbia	170	5,000	2,887	36	21
Florida	120,001	12,000	6,928	12,000	6,928
Georgia	73,801	7,380	4,261	7,380	4,261
Illinois	56,040	5,604	3,235	5,604	3,235
Indiana	115,687	11,569	6,679	11,569	6,679
Iowa	46,068	5,000	2,887	5,000	2,887
Kansas	51,321	5,132	2,963	5,132	2,963
Kentucky	74,117	7,412	4,279	7,412	4,279
Louisiana	43,946	5,000	2,887	5,000	2,887
Maryland	17,044	5,000	2,887	3,579	2,066
Massachusetts	5,960	5,000	2,887	1,252	723
Michigan	64,932	6,493	3,749	6,493	3,749
Minnesota	41,322	5,000	2,887	5,000	2,887
Missouri	57,681	5,768	3,330	5,768	3,330
Nebraska	43,228	5,000	2,887	5,000	2,887
New Jersey	11,826	5,000	2,887	2,483	1,434
New York	23,341	5,000	2,887	4,902	2,830
North Carolina	51,800	5,180	2,991	5,180	2,991
Ohio	97,313	9,731	5,618	9,731	5,618
Pennsylvania	113,903	11,390	6,576	11,390	6,576
South Carolina	33,882	5,000	2,887	5,000	2,887
Tennessee	28,362	5,000	2,887	5,000	2,887
Virginia	29,581	5,000	2,887	5,000	2,887
West Virginia	51,990	5,199	3,002	5,199	3,002
Wisconsin	44,846	5,000	2,887	5,000	2,887
Total	1,376,312				

Proposed 1-year variability limits are the larger of (1) 5,000 tons or (2) 10 percent of the state's budget. 3-year limits are the 1-year limits divided by the square root of three.

The alternative 1-year variability limit is 5,000 tons as long as that amount is between 10 and 21 percent of the state's budget. If 5,000 tons is greater than 21 percent of the state's budget, the state's limit is set at 21 percent of its budget. If 5,000 tons is less than 10 percent of the state's budget, the state's limit is set at 10 percent of its budget.

The NO_X ozone season variability limits have been calculated based on five months of data corresponding to the May through September ozone season. EPA is proposing to use the same approach to calculate ozone season limits that the Agency used to calculate the proposed SO_2 and NO_X annual variability limits described earlier in this section, but adjusted to reflect the ozone season data.

Using that approach, the resulting ozone season 1-year variability limits are 2,100 tons and 10 percent of a state's budget. EPA assigned each state one of these values–either the tonnage limit or the percentage limit, whichever was greater for that state—using the same approach as for the SO_2 and NO_X annual limits described previously. EPA determined the 3-year variability limits as the 1-year limits divided by the square root of three, the same approach used for the SO_2 and NO_X annual limits. The NO_X ozone season limits resulting from this approach are shown in Table IV.F–3.

EPA did not explicitly model ozone season variability limits because it was assumed that the NO_X annual limits would also serve to limit variability in the ozone season and that additional constraints were unnecessary. However, a comparison of the data revealed that these variability limits would be lower than the ozone season emissions shown in EPA's modeling for this proposed rule in seven states, with the difference ranging from less than 100 tons to about 900 tons. Adding these ozone season variability limits would, presumably, change the NO_X emissions projections in the IPM modeling, but the differences are expected not to make a noticeable impact in the overall air quality results.

As with the SO_2 and NO_X annual variability limits, EPA also calculated NO_X ozone season limits using the alternative calculation method described previously; the alternative method adds a ceiling based on the maximum percentage of variability among covered states as observed in the historic heat input data. For NO_X ozone season, the percentage limit ceiling would be 27 percent of a state's budget. The NO_X ozone season limits resulting from this approach are also shown in Table IV.F–3.

EPA requests comments on the NO_X ozone season limits shown in Table IV.F–3.

TABLE IV.F–3—VARIABILITY LIMITS ON NO_X OZONE EMISSIONS FOR 2014 AND LATER FOR ELECTRIC GENERATING UNITS

[Tons]

State	NO_X ozone season emissions budget	Proposed		Alternative	
		1-year limit	3-year average limit	1-year limit	3-year average limit
Alabama	29,738	2,974	1,717	2,974	1,717
Arkansas	16,660	2,100	1,212	2,100	1,212
Connecticut	1,315	2,100	1,212	355	205
Delaware	2,450	2,100	1,212	662	382
District of Columbia	105	2,100	1,212	28	16
Florida	56,939	5,694	3,287	5,694	3,287
Georgia	32,144	3,214	1,856	3,214	1,856
Illinois	23,570	2,357	1,361	2,357	1,361
Indiana	49,987	4,999	2,886	4,999	2,886
Kansas	21,433	2,143	1,237	2,143	1,237
Kentucky	30,908	3,091	1,784	3,091	1,784
Louisiana	21,220	2,122	1,225	2,122	1,225
Maryland	7,232	2,100	1,212	1,953	1,127
Michigan	28,253	2,825	1,631	2,825	1,631
Mississippi	16,530	2,100	1,212	2,100	1,212
New Jersey	5,269	2,100	1,212	1,423	821
New York	11,090	2,100	1,212	2,100	1,212
North Carolina	23,539	2,354	1,359	2,354	1,359
Ohio	40,661	4,066	2,348	4,066	2,348
Oklahoma	37,087	3,709	2,141	3,709	2,141
Pennsylvania	48,271	4,827	2,787	4,827	2,787
South Carolina	15,222	2,100	1,212	2,100	1,212
Tennessee	11,575	2,100	1,212	2,100	1,212
Texas	75,574	7,557	4,363	7,557	4,363
Virginia	12,608	2,100	1,212	2,100	1,212
West Virginia	22,234	2,223	1,284	2,223	1,284
Total	641,614				

Proposed 1-year variability limits are the larger of (1) 2,100 tons or (2) 10 percent of the state's budget. 3-year limits are the 1-year limits divided by the square root of three.

The alternative 1-year variability limit is 2,100 tons as long as that amount is between 10 and 27 percent of the state's budget. If 2,100 tons is greater than 27 percent of the state's budget, the state's limit is set at 27 percent of its budget. If 2,100 tons is less than 10 percent of the state's budget, the state's limit is set at 10 percent of its budget.

As discussed in section V.D, the proposed FIPs would apply the 1-year variability limits commencing in 2014 and the 3-year variability limits commencing in 2016, noting that application of the 3-year average limits in 2016 would serve to limit each state's emissions in 2014 and 2015. The Agency also requests comment on whether the remedy in the proposed FIPs should be modified so that the limits would apply starting in 2012 instead of 2014. In addition, the direct control remedy option on which EPA requests comments includes assurance provisions based on these variability limits that would apply starting in 2012. Thus, EPA also explains later what variability limits would apply in 2012 and 2013. The 1-year variability limits for 2012 and 2013 would be the same as the variability limits for 2014 and later in Tables IV.F–1, IV.F–2, and IV.F–3 for all state budgets except for the SO_2 budgets for the 15 states comprising the stringent SO_2 tier ("group 1"), which have different SO_2 budgets in 2012 and 2013 than in 2014 and beyond.

If EPA finalizes a remedy that uses the 2012 and 2013 variability limits, EPA would also start applying the 3-year variability limits in 2014 (for all state budgets except group 1 SO_2 budgets) which would serve to limit each state's emissions in 2012 and 2013, in the same way that starting the 3-year limits in 2016 would serve to limit emissions in 2014 and 2015 under the proposed approach. The 3-year variability limits would be the same as the 3-year limits for 2014 and later in Tables IV.F–1, IV.F–2, and IV.F–3.

In this alternative approach, the 15 SO_2 group 1 states, which have different SO_2 budgets in 2012 and 2013 than in 2014 and beyond, would be subject to different 1-year variability limits in 2012 and 2013 than in later years. All of the group 1 states have sufficiently large SO_2 budgets in 2012 and 2013 that the tonnage limit of 1,700 tons would not apply and the 1-year limits would be 10 percent of the state SO_2 budgets. The 2012 and 2013 1-year limits on SO_2 emissions for these 15 states under this alternative approach are shown later in Table IV.F–4.

Additionally, commencing in 2013, EPA would apply in these 15 states a distinct 2-year average variability limit on SO_2 emissions for the years 2012 and 2013. Analogous to the 3-year average in subsequent years, this 2-year average limit would restrict average variability in 2012 and 2013 more than the 1-year average alone. Table IV.F–4 shows, for this alternative approach, 2-year variability limits on SO_2 emissions for 2012 and 2013 for the 15 group 1 states. For these states, the 3-year variability limits for later years would be as shown in Tables IV.F–1, IV.F–2, and IV.F–3.

For an alternative approach where variability limits start in 2012 instead of 2014, EPA considered—instead of two-year average limits on SO_2 emissions in the 15 group 1 states in 2012 and 2013—applying 3-year average limits in these states starting in 2014. This would be the same method as for all other state budgets under the alternative where variability limits start in 2012. However, because the 15 group 1 states have different SO_2 budgets in 2012 and 2013 than in 2014 and beyond, calculation of the 3-year average limits to apply in years spanning the two budget levels is less straightforward. EPA analyzed this alternative method for the 15 SO_2 group 1 states and compared results to the results using the 2-year average limits in 2012 and 2013 for these states, and determined that the 2-year average approach is reasonable. *See* the Power Sector Variability TSD for more information.

Table IV.F–4 includes 1-year and 2-year variability limits calculated according to the proposed methodology. The 2-year limits are the 1-year limits divided by the square root of two. The table does not include separate columns with variability limits calculated according to the alternative calculation method (*i.e.*, the method that adds a ceiling based on the maximum percentage of variability in historic data, described previously) because for the SO_2 budgets in Table IV.F–4 the alternative calculation method would yield identical results to the proposed method. The Power Sector Variability TSD contains more details on the variability limits.

TABLE IV.F–4—2012–2013 ONE- AND TWO-YEAR VARIABILITY LIMITS ON SO_2 EMISSIONS FOR GROUP 1 STATES FOR ELECTRIC GENERATING UNITS

[Tons]

State	SO_2 annual emissions budget	1-year limit	Two-year average limit
Georgia	233,260	23,326	16,494
Illinois	208,957	20,896	14,775
Indiana	400,378	40,038	28,311
Iowa	94,052	9,405	6,650
Kentucky	219,549	21,955	15,524
Michigan	251,337	25,134	17,772
Missouri	203,689	20,369	14,403
New York	66,542	6,654	4,705
North Carolina	111,485	11,149	7,883
Ohio	464,964	46,496	32,878
Pennsylvania	388,612	38,861	27,479
Tennessee	100,007	10,001	7,072
Virginia	72,595	7,260	5,133
West Virginia	205,422	20,542	14,526
Wisconsin	96,439	9,644	6,819

1-year variability limits calculated by the proposed method are the larger of (1) 1,700 tons or (2) 10 percent of the state's budget. Two-year limits are the 1-year limits divided by the square root of two.

The alternative 1-year variability limit is 1,700 tons as long as that amount is between 10 and 28 percent of the state's budget. If 1,700 tons is greater than 28 percent of the state's budget, the state's limit is set at 28 percent of its budget. If 1,700 tons is less than 10 percent of the state's budget, the state's limit is set at 10 percent of its budget. The alternative calculation method would yield identical limits to the limits determined using the proposed method for the budgets in Table IV.F–4, because for each of these budgets, 1,700 tons is less than 10 percent of the budget.

3. Summary of Emissions Reductions Across All Covered States

Table IV.F–5 presents projected power sector emissions in the base case (*i.e.*, without the proposed Transport Rule or CAIR) compared to projected emissions with the proposed Transport Rule in 2012 and 2014 for all covered states. Table IV.F–6 presents 2005 historical power sector emissions compared to projected emissions with the Transport Rule in 2012 and 2014.

TABLE IV.F–5—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSIONS REDUCTIONS IN COVERED STATES WITH THE TRANSPORT RULE COMPARED TO BASE CASE WITHOUT TRANSPORT RULE OR CAIR

[Million tons]

	2012 base case emissions	2012 transport rule emissions	2012 emissions reductions	2014 base case emissions	2014 transport rule emissions	2014 emissions reductions
SO_2	8.4	3.4	5.0	7.2	2.6	4.6
Annual NO_X	2.0	1.3	0.7	2.0	1.3	0.7
Ozone Season NO_X	0.7	0.6	0.1	0.7	0.6	0.1

Note: Emissions differ from emissions budgets due to banking.

TABLE IV.F–6—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSIONS REDUCTIONS IN COVERED STATES WITH THE TRANSPORT RULE COMPARED TO 2005 ACTUAL EMISSIONS

[Million tons]

	2005 actual emissions	2012 transport rule emissions	2012 emissions reductions from 2005	2014 transport rule emissions	2014 emissions reductions from 2005
SO_2	8.9	3.4	5.5	2.6	6.3

TABLE IV.F–6—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSIONS REDUCTIONS IN COVERED STATES WITH THE TRANSPORT RULE COMPARED TO 2005 ACTUAL EMISSIONS—Continued

[Million tons]

	2005 actual emissions	2012 transport rule emissions	2012 emissions reductions from 2005	2014 transport rule emissions	2014 emissions reductions from 2005
Annual NO_X	2.7	1.3	1.4	1.3	1.4
Ozone Season NO_X	0.9	0.6	0.3	0.6	0.3

Note: Emissions differ from emissions budgets due to banking.

G. How the Proposed Approach Is Consistent With Judicial Opinions Interpreting Section 110(a)(2)(D)(i)(I) of the Clean Air Act

The methodology described previously quantifies states' significant contribution and interference with maintenance in a manner that is consistent with the decisions of the DC Circuit. As discussed in section III previously, the DC Circuit has issued two significant decisions addressing the requirements of 110(a)(2)(D)(i)(I). The first opinion largely upheld the NO_X SIP Call, *Michigan* v. *EPA,* 213 F.3d 663 (DC Cir. 2000), and the second found significant flaws in the CAIR, *North Carolina* v. *EPA,* 531 F.3d. 896 (DC Cir. 2008). In both cases, the Court considered aspects of the methodology used by EPA to identify emissions that, pursuant to section 110(a)(2)(D)(i)(I), must be eliminated due to their impact on air quality in downwind states. EPA believes that the methodology used in this proposed Transport Rule is consistent with both opinions and rectifies the flaws the *North Carolina* Court identified with the methodology used in CAIR. The methodology used for this proposed rule relies on state-specific data to analyze each individual state's significant contribution, uses air quality considerations in addition to cost considerations to identify each state's significant contribution, and gives independent meaning to the "interference with maintenance" prong. This methodology is then applied in a reasonable manner consistent with the relevant judicial opinions.

In *North Carolina,* the Court held that EPA's approach to evaluating significant contribution was inadequate because, by evaluating only whether emissions reductions were highly cost effective "at the regional level assuming a trading program", it failed to conduct the required state-specific analysis of significant contribution. *See id.* at 907. EPA, the Court concluded, "never measured the 'significant contribution' from sources within an individual state to downwind nonattainment areas." *Id.* The Court did not, however, disturb the air-quality-based methodology used by EPA to identify the states with contributions large enough to warrant further consideration.

For this proposed transport rule, EPA uses a first step similar to that used in the CAIR to identify the states with relatively large contributions. However, in contrast to the CAIR, it then uses a state-specific analysis. Instead of identifying a single emissions level that could be achieved by the application of highly cost effective controls in the region, EPA determines, on a state-by-state basis what reductions could effectively be achieved by sources in that state. EPA's new approach does not, as the CAIR methodology did, establish a regional cap on emissions that is then divided into state budgets that set the emission reduction requirements for each state. Instead, EPA develops, for each covered state, emissions budgets based on the reductions achievable at a particular cost per ton in that particular state, taking into account the need to ensure reliability of the electric generating system. The selected cost/ton levels reflect consideration of both cost factors and air quality factors including the estimated impact of upwind states' emissions on each downwind receptor.

In addition, in developing this approach, EPA was guided by the Court's holdings regarding the use of cost to identify significant contribution. Specifically, the Court held in *Michigan* that EPA could "in selecting the 'significant' level of 'contribution' under section 110(a)(2)(D)(i)(I), choose a level corresponding to a certain reduction in cost." *North Carolina,* 531 F.3d at 917 (citing *Michigan,* 213 F.3d at 676–77). This holding also supported the Court's conclusion in *Michigan* that it was acceptable for EPA to apply a uniform cost-criterion across states. *See Michigan,* 213 F.3d at 679. In the CAIR case, the Court rejected EPA's analysis, not because it relied on cost considerations to identify significant contribution, but because it found that EPA had failed to draw the significant contribution line at all. *See North Carolina,* 531 F.3d at 918 ("* * * here EPA did not draw the [significant contribution] line at all. It simply verified sources could meet the SO_2 caps with controls EPA dubbed 'highly cost-effective.' "). The holdings in *Michigan* regarding the use of cost and a uniform cost-criterion across states were left undisturbed. *See, e.g., North Carolina,* 531 F.3d at 917 (explaining that in Michigan the Court held that "EPA may 'after [a state's] reduction of all [it] could * * * cost-effectively eliminate[ ],' consider 'any remaining contribution insignificant' "). In fact, the Court acknowledged that, based on the Michigan holdings, the measurement of a state's significant contribution need not "directly correlate with each state's individualized air quality impact on downwind nonattainment relative to other upwind states." *North Carolina,* 531 F.3d at 908.

For these reasons, EPA determined that it was appropriate in this rulemaking to consider the cost of controls to determine what portion of a state's contribution is its "significant contribution." However, EPA also heeded the *North Carolina* Court's warning that "EPA can't just pick a cost for a region, and deem 'significant' any emissions that sources can eliminate more cheaply." *North Carolina,* 531 F.3d at 918. Thus, in this rulemaking, EPA departs from the practice used in the NO_X SIP Call and in CAIR of evaluating, based solely on the cost of control required in other regulatory environments, what controls would be considered "highly-cost-effective." Instead, as part of its determination of a reasonable cost per ton for upwind state control, EPA evaluates the air quality impact of reductions at various cost levels and considers the reasonableness of possible cost thresholds as part of a multi-factor analysis.

In addition, the methodology used in this rulemaking gives independent meaning to the interfere with maintenance prong of section 110(a)(2)(D)(i)(I). In *North Carolina,* the Court concluded that CAIR improperly "gave no independent significance to the 'interfere with maintenance' prong of section 110(a)(2)(D)(i)(I) to separately identify upwind sources interfering with downwind maintenance." *North Carolina,* 531 F.3d at 910. EPA rectified this flaw in this rulemaking by separately identifying downwind "nonattainment sites" and downwind "maintenance sites." EPA decided to consider upwind states' contributions not only to sites that EPA projected would be in nonattainment, but also to sites that, based on the historic variability of their emissions, EPA determined may have difficulty maintaining the relevant standards. The specific mechanism EPA used to implement this approach is described in detail in section IV.C. previously. For annual $PM_{2.5}$, this approach identified 16 maintenance sites in addition to the 32 nonattainment sites identified in the analysis of nonattainment receptors. For 24-hour $PM_{2.5}$ this approach identified 38 maintenance sites in addition to the 92 nonattainment sites identified in the analysis of nonattainment receptors. For ozone it identified 16 maintenance sites in addition to the 11 ozone nonattainment sites identified.

EPA applied this methodology using available information and data to measure the emissions from states in the eastern United States that significantly contribute to nonattainment or interfere with maintenance in downwind areas with regard to the 1997 and 2006 $PM_{2.5}$ NAAQS and the 1997 ozone NAAQS. Although EPA has not completely quantified the total significant contribution of these states with regard to all existing standards, EPA has determined, on a state-specific basis, that the emissions prohibited in the proposed FIPs are either part of or constitute the state's significant contribution and interference with maintenance. Thus, elimination of these emissions will, at a minimum, make measurable progress towards satisfying the 110(a)(2)(D)(i)(I) prohibition on significant contribution and interference with maintenance.

H. Alternative Approaches Evaluated But Not Proposed

EPA evaluated a number of alternative approaches to defining significant contribution and interference with maintenance in addition to the approach proposed in this rule. Stakeholders suggested a variety of ideas. EPA considered all suggested approaches.

EPA evaluated approaches including those based solely on air quality, based solely on cost with a uniform cost in all states, based on cost per air quality impact (*e.g.*, \$ per μg/m^3), and binning of states based on air quality impact. Detailed descriptions of the alternative approaches that EPA evaluated are in a TSD in the docket titled "Alternative Significant Contribution Approaches Evaluated."

EPA is not proposing any of the alternative approaches listed here. However, the proposed approach (described in section IV.D) incorporates some elements from these approaches.

V. Proposed Emissions Control Requirements

This section describes the proposed emissions control requirements in detail. The section starts with V.A which discusses the pollutants included in the proposal, followed by V.B which discusses the source categories covered. Section V.C discusses the timing of the proposed emissions control requirements. Section V.D describes the proposed approach to implement the emission reduction requirements, starting with a description of the NO_X SIP Call and CAIR approaches to implementing reductions and the judicial opinions on those approaches, then describing in detail the proposed "remedy" (State Budgets/Limited Trading) for FIPs that would implement the emissions reductions, and explaining the structure and key elements of the proposed Transport Rule trading program rules for State Budgets/Limited Trading. Section V.D also describes two alternative remedies on which EPA requests comment. Section V.E presents projected costs and emissions for each remedy option. Section V.F discusses the transition from the CAIR cap and trade programs to the proposed Transport Rule programs. Section V.G discusses interactions of the proposed programs with the existing Title IV and NO_X SIP Call programs.

A. Pollutants Included in This Proposal

In this action, EPA is proposing FIPs to directly regulate upwind emissions of SO_2 and NO_X because of their impact on downwind states' ability to attain and maintain the $PM_{2.5}$ NAAQS. EPA is also proposing to regulate upwind emissions of NO_X because of their impact on 8-hour ozone attainment and maintenance in downwind states. Our rationale for regulating these precursor pollutants is discussed in section IV.B. In this section, we also explain the regulatory mechanism we are proposing to use to regulate these pollutants and take comment on two alternative options.

B. Source Categories

EPA is proposing to require emissions reductions from the power sector. This section discusses EPA's rationale for proposing to control power sector emissions, and our rationale for not proposing to control emissions from other source categories at this time.

1. Propose To Control Power Sector Emissions

The proposed Transport Rule FIPs would require EGUs with capacity greater than 25 MWe in the covered states to reduce emissions of SO_2, NO_X, and ozone season NO_X. *See* section V.D.4., later, for a detailed description of the proposed applicability requirements.[77]

Electric generating units are important sources of SO_2 and NO_X emissions. In 2012, considering other controls that will be in place, EPA projects that if a Transport Rule is not implemented, EGUs would emit more than 70 percent of the total man-made SO_2 emissions and about 20 percent of the total man-made NO_X emissions in the group of 32 states that would be affected by this rule (*see* Table III.A–1 in section III for lists of states).[78]

EPA has previously conducted extensive analyses of the cost and emissions impacts of SO_2 and NO_X reduction policies on the power sector using the Integrated Planning Model (IPM). Examples include EPA's IPM analyses of a number of multi-pollutant bills, including the Clean Air Planning Act (S. 843 in 108th Congress), the Clean Power Act (S. 150 in 109th Congress), the Clear Skies Act of 2005 (S. 131 in 109th Congress), the Clear Skies Act of 2003 (S. 485 in 108th Congress), and the Clear Skies Manager's Mark (of S. 131). EPA also analyzed several power sector multi-pollutant scenarios in July 2009 at the request of Senator Tom Carper. These analyses are on EPA's Web site at: (*http://www.epagov/airmarkets/progsregs/cair/multi.html*). EPA's IPM analysis for CAIR is another example: (*http://www.epagov/airmarkets/progsregs/epa-ipm/cair/index.html*).

Based on these analyses, EPA believes that there exist reasonable means for EGUs to make substantial reductions in emissions of SO_2 and NO_X. EPA also believes that, at this time, EGUs can

[77] Certain non-EGUs and smaller EGUs were included in the CAIR NO_X ozone season program in some CAIR states. EPA proposes that such units would not be covered by the Transport Rule requirements; see section V.F in this preamble for further discussion of these units.

[78] Emissions estimates are based on the 2012 baseline projections described in section IV in this preamble.

reduce SO_2 and NO_X emissions more cost-effectively than other source categories (*see* section IV.D for discussion of control costs for non-EGU source categories). For these reasons, EPA has decided to require reductions in SO_2 and NO_X emissions from EGUs in the FIPs in this proposed rule. EPA requests comments on these proposed FIPs and its proposal to require reductions from EGUs.

2. Other Source Categories Are Not Included

In these proposed FIPs, EPA is not proposing to include emission reduction requirements for sources other than EGUs.[79]

a. Why EPA Does Not Require Reductions From Other Source Categories To Address Transport Requirements for $PM_{2.5}$

In the proposed FIPs to address the section 110(a)(2)(D)(i)(I) requirements with respect to the 1997 and 2006 $PM_{2.5}$ standards, EPA proposes to regulate only emissions from EGUs. As discussed previously in section IV.D, EPA's review of the costs of EGU and non-EGU controls resulted in a conclusion that substantial SO_2 and NO_X reductions from EGUs are available at a cost per ton that is lower than the cost per ton of non-EGU controls. Other analyses discussed in section IV.D demonstrated that these EGU reductions are sufficient to eliminate the quantity of emissions identified by EPA as significantly contributing to or interfering with maintenance of the 1997 $PM_{2.5}$ NAAQS in downwind areas. This same section explains that EGU reductions substantially address eliminating the quantity of emissions identified by EPA as significantly contributing to or interfering with maintenance of the 2006 $PM_{2.5}$ NAAQS, and this same section explains the need for EPA to further analyze remaining winter $PM_{2.5}$ exceedances. This conclusion does not, in any way, address whether a FIP promulgated by EPA or SIPs promulgated by the states should include reductions from non-EGU sources in order to eliminate significant contribution and interference with maintenance for any other NAAQS, including the 1997 ozone NAAQS and future NAAQS for $PM_{2.5}$.

b. Why EPA Does Not Propose To Require Reductions From Other Source Categories To Address Transport Requirements for Ozone

In the FIPs for this proposed rule, EPA is only proposing to require reductions from EGUs to address emissions from those source categories that significantly contribute to or interfere with maintenance of the 1997 ozone NAAQS. As discussed previously in section IV.D, EPA's review of the costs of EGU and non-EGU controls resulted in a conclusion that significant NO_X emissions reductions from EGU are available at a cost per ton that is lower than the cost per ton of non-EGU NO_X controls. The same section also explains the need for EPA to further analyze whether fully addressing upwind state responsibilities to reduce NO_X emissions that contribute to downwind nonattainment and maintenance problems requires additional reductions at higher cost per ton, which again would involve analysis of potential EGU and non-EGU reductions and costs. EPA will be moving forward to complete its assessment of pollution transport for the 1997 ozone NAAQS as soon as possible.

For future ozone and $PM_{2.5}$ NAAQS, EPA intends to quantify the emissions reductions needed to satisfy the requirements of 110(a)(2)(D)(i)(I) with respect to those NAAQS. EPA has not made any determinations or assessments regarding whether reductions from source categories other than EGUs will be needed to achieve the necessary reductions in each state.

C. Timing of Proposed Emissions Reduction Requirements

EPA is proposing an initial phase of reductions in 2012 followed by a second phase in 2014. Sources will be required to comply with the annual SO_2 and NO_X requirements by January 1, 2012 and January 1, 2014 for the first and second phases, respectively. Similarly, sources will be required to comply with the ozone season NO_X requirements by May 1, 2012, and by May 1, 2014. EPA chose these dates to coordinate with the NAAQS attainment deadlines and to assure that reductions are made as expeditiously as practicable, as described later in this section. This section also discusses how the compliance deadlines address the Court's concern about timing. Additionally, this section explains that EPA will consider additional reductions to address the NAAQS in the future.

1. Date for Prohibiting Emissions That Significantly Contribute or Interfere With Maintenance of the $PM_{2.5}$ NAAQS

For all areas designated as nonattainment with respect to the 1997 $PM_{2.5}$ NAAQS, the SIP deadline for attaining that standard must be as expeditious as practicable but no later than April 2010, with a possible extension to no later than April 2015. Many areas have already come into attainment by the April 2010 deadline due in part to reductions achieved under CAIR. Because the 2010 deadline will have passed before the Transport Rule is finalized, we decided to coordinate the deadline for eliminating significant contribution under this rule with respect to the 1997 $PM_{2.5}$ NAAQS with the April 2015 deadline that applies to areas that will need an extension of the April 2010 deadline. For all areas designated as nonattainment with respect to the 2006 24-hour $PM_{2.5}$ NAAQS, the attainment deadline must be as expeditious as practicable but no later than December 2014 with a possible extension to as late as December 2019.[80]

Upwind emissions reductions achieved by the 2014 emissions year will help areas that failed to meet the April 2010 deadline, to meet the April 2015 deadline for the 1997 $PM_{2.5}$ NAAQS. These reductions will also help areas meet the December 2014 attainment deadline with respect to the 2006 $PM_{2.5}$ NAAQS. Any areas not meeting that deadline can request a 5-year extension to December 2019.

Further, a deadline of January 1, 2014 also provides adequate and reasonable time for sources to plan for compliance with the Transport Rule and install any necessary controls. EPA believes that this deadline is as expeditious as practicable for the installation of the controls needed for compliance (*see* further discussion in section IV.D).

[79] See section IV.D.3 for discussion of non-EGUs that were included in the CAIR NO_X ozone season trading program.

[80] Section 172(a)(2) of the Clean Air Act provides that "the attainment date for an area designated nonattainment with respect to a national primary ambient air quality standard shall be the date by which attainment can be achieved as expeditiously as practicable, but no later than 5 years from the date such area was designated nonattainment under section 7407(d) of this title, except that the Administrator may extend the attainment date to the extent the Administrator determines appropriate, for a period no greater than 10 years from the date of designation as nonattainment, considering the severity of nonattainment and the availability and feasibility of pollution control measures." Designations for the 2006 24-hour $PM_{2.5}$ NAAQS became effective on December 14, 2009.

2. Date for Prohibiting Emissions That Significantly Contribute or Interfere With Maintenance of the 1997 Ozone NAAQS

Ozone nonattainment areas must attain permissible levels of ozone "as expeditiously as practicable," but no later than the date assigned by EPA in the ozone implementation rule (40 CFR part 51). The areas designated nonattainment in 2004 with respect to the 1997 8-hour ozone NAAQS in the eastern United States were assigned maximum attainment dates corresponding to the end of the 2006, 2009, and 2012 ozone seasons. Many areas have already attained due in part to CAIR, federal mobile source standards, and other local, state, and federal measures. Those that have not yet attained the standard have maximum attainment dates ranging from 2010 (these are the 2009 areas that have been granted a 1-year extension due to clean data in 2009) to 2018. Areas designated "serious" nonattainment areas have a June 2013 maximum attainment deadline. The proposed Transport Rule's first phase of reductions in 2012 will help the remaining areas with June 2013 maximum attainment deadlines attain the 1997 8-hour ozone NAAQS by their deadline. The reductions will also improve air quality in areas with later deadlines.

3. Reductions Required by 2012 To Ensure That Significant Contribution and Interference With Maintenance Are Eliminated as Expeditiously as Practicable

EPA is requiring an initial phase of reductions by 2012. These reductions are necessary to ensure that significant contribution and interference with maintenance are eliminated as expeditiously as practicable. This will in turn assist downwind states to achieve attainment as expeditiously as practicable as required by the CAA.

Because the proposed rule, if finalized, will replace the CAIR, EPA cannot assume that after this rule is finalized, EGUs would continue to emit at the reduced emissions levels achieved by CAIR. Instead, it is the emissions reductions requirements in the proposed FIPs that will determine the level of EGU emissions in the eastern United States. For these reasons, EPA is proposing to require an initial phase of reductions by 2012 which would ensure that existing and planned SO_2 and NO_X controls operate as anticipated.

4. How Compliance Deadlines Address the Court's Concern About Timing

As directed by the Court in *North Carolina* v. *EPA,* 531 F.3d 896 (DC Cir. 2008), and described previously, EPA has established the compliance deadlines in the proposed rule based on the respective NAAQS attainment requirements and deadlines applicable to the downwind nonattainment and maintenance sites.

The 2012 deadline for compliance with the limits on ozone-season NO_X emissions is coordinated with the June 2013 maximum attainment deadline for serious ozone nonattainment areas (taking into account the need for reductions by 2012 to demonstrate attainment by that date). This deadline is also consistent with the requirement that states attain the NAAQS as expeditiously as practicable.

The 2014 deadline for compliance with the limits on annual NO_X and annual SO_2 emissions is coordinated with the April 2015 maximum attainment deadline for areas that received the maximum 5-year extension of the 5-year attainment deadline for the 1997 $PM_{2.5}$ NAAQS (taking into account the need for reductions by 2014 to demonstrate attainment by April 2015). This 2014 compliance deadline is also consistent with December 2014 attainment deadline (5 years from designation, in the absence of an extension) for areas designated nonattainment for the 2006 $PM_{2.5}$ NAAQS. Areas unable to meet this 2014 deadline may seek a maximum 5-year extension to 2019.

In addition, the 2012 compliance deadline for the first-phase of annual NO_X and annual SO_2 emissions reductions will assure the reductions are achieved as expeditiously as practicable. EPA established the interim 2012 compliance deadline for annual NO_X and annual SO_2 reductions because a significant number of reductions can be achieved by 2012. However, given the time needed to design and construct scrubbers at a large number of facilities, EPA believes the 2014 compliance date is as expeditious as practicable for the full quantity of SO_2 reductions necessary to fully address the significant contribution and interference with maintenance. Requiring reductions in transported pollution as expeditiously as practicable, as well as within maximum deadlines, helps to promote attainment as expeditiously as practicable. This is consistent with statutory provisions that require states to adopt SIPs that provide for attainment as expeditiously as practicable and within the applicable maximum deadlines.

5. EPA Will Consider Additional Reductions in Pollution Transport To Assist in Meeting Any Revised or New NAAQS

a. Ozone

As noted, in a January 19, 2010, notice of proposed rulemaking, EPA proposed to strengthen the NAAQS for ozone. In that notice, EPA proposed levels for the ozone standard to a level within the range of 0.060 to 0.070 parts per million. EPA also proposed in this same notice to establish a distinct cumulative, seasonal "secondary" standard, designed to protect sensitive vegetation and ecosystems, including forests, parks, wildlife refuges and wilderness areas.[81]

EPA expects to finalize the revised NAAQS for ozone in August 2010. After the NAAQS are finalized, EPA will be able to identify areas that are expected to have difficulty attaining and maintaining those standards and will evaluate and analyze the impact of upwind state emissions in those areas with regard to those standards. EPA has already begun the technical background work necessary to allow it to move quickly, once the revised ozone standards are promulgated, with a proposal to address upwind emissions that significantly contribute to nonattainment of or interfere with maintenance of those standards. Because that analysis will take some time, and because EPA recognizes the urgency of responding to the concerns raised by the Court in *North Carolina* v. *EPA*, EPA intends to address the requirements of 110(a)(2)(D)(i)(I) with respect to the revised ozone standards in a subsequent proposal. Addressing the 110(a)(2)(D)(i)(I) requirements for the new NAAQS shortly after promulgation of those NAAQS would help clarify the requirements related to transported emissions before downwind state nonattainment SIPs are due. In doing so, the transport rule would aid downwind states in developing plans for attaining and maintaining the new NAAQS.

b. Fine Particles

EPA is also on a schedule to review and, if necessary update the $PM_{2.5}$ NAAQS. This review is scheduled for completion in October 2011. EPA plans

[81] This proposed cumulative, seasonal standard is expressed as an annual index of the sum of weighted hourly concentrations, cumulated over 12 hours per day (8 a.m. to 8 p.m.) during the consecutive 3-month period within the O_3 season with the maximum index value, set at a level within the range of 7 to 15 ppm-hours.

to conduct background technical analyses so that EPA will be prepared to move quickly, if necessary, with a transport rule related to any revised $PM_{2.5}$ NAAQS.

D. Implementing Emissions Reductions Requirements

In this rule, EPA is proposing FIPs to eliminate the significant contribution and interference with maintenance EPA has identified in this action. We are proposing one "remedy" option to implement the necessary emissions reductions and taking comment on two other options. Before presenting these options we briefly summarize the approaches used in the NO_X SIP Call and CAIR.

1. Approaches Taken in NO_X SIP Call and CAIR

In the NO_X SIP Call and CAIR, EPA developed emissions trading programs as possible remedies to 110(a)(2)(D)(i)(I) SIP deficiencies. States covered by the rules were given the option of joining the trading programs and EPA determined that, by doing so, they would satisfy the requirements of 110(a)(2)(D)(i)(I) with respect to specific NAAQS. The NO_X SIP Call provided an ozone-season NO_X trading program and addressed the requirements of the ozone NAAQS only. The CAIR provided SO_2, annual NO_X, and ozone-season NO_X trading programs, and addressed both the 1997 ozone and the 1997 $PM_{2.5}$ NAAQS.

NO_X SIP Call approach. The NO_X SIP Call proposed a regional cap and trade program as a way to make cost-effective NO_X reductions. Created after years of scientific research and air quality data analyses showed that upwind NO_X emissions can contribute significantly to ozone nonattainment in downwind states, the NO_X Budget Trading Program (NBP) followed several other major efforts to reduce NO_X from large, stationary sources. These initiatives included the Acid Rain Program, OTC NO_X Budget Program, New Source Review, New Source Performance Standards, application of Reasonably Available Control Technology to existing sources, and other state efforts.

By notice dated October 27, 1998 (63 FR 57356), EPA took final action to require states to prohibit specified amounts of emissions of one of the main precursors of ground-level ozone, NO_X, in order to reduce ozone transport across state boundaries in the eastern half of the United States. EPA found that sources in 23 states emit NO_X in amounts that significantly contribute to nonattainment of the 1-hour ozone NAAQS in downwind states. EPA set forth requirements for each of the affected upwind states to submit SIP revisions prohibiting those amounts of NO_X emissions that significantly contribute to downwind air quality problems. EPA established statewide NO_X emissions budgets for the affected states. States had the flexibility to adopt the appropriate mix of controls for their state to meet the NO_X emissions reductions requirements of the SIP call.

In the final regulation, EPA offered to administer a multi-state NO_X Budget Trading Program for states affected by the NO_X SIP Call. The NO_X Budget Trading Program was an ozone season (May 1 to September 30) cap and trade program for EGUs and large industrial combustion sources, primarily boilers and turbines. The program used a regionwide cap for ozone season NO_X emissions. The cap was the sum of the state emissions budgets established by EPA under the NO_X SIP Call regulation to help states meet their SIP obligations. Authorizations to emit, known as allowances, were allocated to affected sources based on state trading budgets. The NO_X allowance market enabled sources to trade (buy and sell) allowances throughout the year. Sources could reduce NO_X emissions in any manner. Options included adding emissions control technologies, replacing existing controls with more advanced technologies, optimizing existing controls, or switching fuels. At the end of every ozone season, each source surrendered sufficient allowances to cover its ozone season NO_X emissions (each allowance represents one ton of NO_X emissions). This process is called annual reconciliation. If a source did not have enough allowances to cover its emissions, EPA automatically deducted allowances from the following year's allocation at a 3:1 ratio. If a source had excess allowances because it reduced emissions beyond required levels, it could sell the unused allowances or bank (save) them for use in a future ozone season. To accurately monitor and report emissions, sources use continuous emission monitoring systems (CEMS) or other approved monitoring methods under EPA's stringent monitoring requirements (Title 40 of the Code of Federal Regulations [CFR], Part 75).

The NO_X SIP Call cap and trade program was a way to make cost-effective NO_X reductions. Under the NO_X SIP Call, states had the flexibility to determine the mix of controls to meet their emissions reductions requirements. However, the rule provides that if the SIP controls EGUs, then the SIP must establish a budget, or cap, for EGUs. The EPA recommended that each state authorize a trading program for NO_X emissions from EGUs. Each of the states required to submit a NO_X SIP under the NO_X SIP Call chose to adopt the cap and trade program regulating large boilers and turbines. Each state based its cap and trade program on a model rule developed by EPA. Some states essentially adopted the full model rule as is, while other states adopted the model rule with changes to the sections that EPA specifically identified as areas in which states may have some flexibility. The NO_X SIP Call cap and trade program, modeled closely after the OTC NO_X Budget Program, was phased in starting in 2003 for the OTC states, with the majority of affected states participating as of 2004.

CAIR Approach. In May 2005, EPA promulgated CAIR to address emissions in 28 states and the District of Columbia that it found contribute significantly to nonattainment of the 1997 $PM_{2.5}$ and 8-hour ozone NAAQS in downwind states. The EPA required these upwind states to revise their SIPs to include control measures to reduce emissions of SO_2 and/or NO_X. Reducing upwind precursor emissions helps the downwind $PM_{2.5}$ and 8-hour ozone nonattainment areas achieve the NAAQS. Moreover, reducing upwind emissions makes it possible for attainment to be achieved in a more equitable, cost-effective manner than if each nonattainment area attempted to achieve the NAAQS by implementing local emissions reductions alone.

In CAIR, EPA offered states optional regionwide cap and trade programs, which were similar to the SO_2 trading program in Title IV of the CAA and the NO_X Budget Trading Program in the NO_X SIP Call. CAIR required implementation of emissions reductions requirements for SO_2 and NO_X in two phases. The first phase of NO_X reductions started in 2009 (covering 2009–2014) and the first phase of SO_2 reductions began in 2010 (covering 2010–2014); the second phase of reductions for both NO_X and SO_2 would start in 2015 (covering 2015 and thereafter). The required emissions reductions requirements are based on controls that are known to be highly cost effective for EGUs. CAIR also included model rules for multi-state cap and trade programs for annual SO_2 and NO_X emissions for $PM_{2.5}$, and seasonal NO_X emissions for ozone, that states could choose to adopt to meet the required emissions reductions in a flexible and cost-effective manner. The CAIR provided for the NO_X SIP Call cap and trade program to be replaced by the

CAIR ozone season NO_X trading program.

The U.S. Court of Appeals granted several petitions for review of the CAIR and remanded the rule to EPA. Because the Court decided to remand the rule without vacatur, however, CAIR remains in effect. This proposed rule would replace the CAIR upon final promulgation.

2. Judicial Opinions

Challenges to both the NO_X SIP Call and the CAIR were brought before the U.S. Court of Appeals for the DC Circuit. In *Michigan* v. *EPA*, 213 F.3d 663, the Court largely upheld the NO_X SIP Call. The portion of this opinion most directly related to the remedy selected by EPA, discusses EPA's decision to utilize a uniform control strategy. The Court rejected two specific challenges to the requirement that "all covered jurisdictions, regardless of amount of contribution, reduce their NO_X by an amount achievable with "highly cost-effective controls." *Id.* at 679. EPA's approach, Petitioners first alleged, was irrational because it did not take into account differences in individual states" respective contributions to downwind nonattainment. Both small and large contributors were required to make reductions achievable by the application of highly cost effective controls. The court rejected this challenge finding that this result "flows ineluctably from EPA's decision to draw the 'significant contribution' line on the basis of cost differentials." *Id.*

Petitioners' second objection to the use of uniform controls was that it failed to take into account the fact that the location of emissions reductions may affect the impact of those reductions on downwind nonattainment areas. Petitioners argued that because reductions closer to the nonattainment area have a greater benefit, EPA's use of a highly-cost-effective standard and region-wide emissions trading did not guarantee that it would have secured the rule's health benefits at the lowest cost. *See id.* The Court rejected this challenge also, giving deference to EPA's judgment that non-uniform regional approaches would not " 'provide either a significant improvement in air quality or a substantial reduction in cost.' " *Id.* (quoting 63 FR 57423).

Petitioners challenging the CAIR also raised issues related to EPA's use of an interstate trading program to satisfy the requirements of section 110(a)(2)(D)(i)(I). Petitioners challenged both the trading program itself and the state budgets. These budgets were used to determine the number of emission allowances allocated to sources in each state or, if the state chose not to participate in the trading programs, the specific emission reduction requirements for that state.

The Court concluded, in *North Carolina* v. *EPA*, 531 F.3d 896, that EPA had not demonstrated that the 110(a)(2)(D)(i)(I) remedy promulgated in CAIR would effectuate the statutory mandate of section 110(a)(2)(D)(i)(I) and promote the goal of prohibiting contributing sources within one state from contributing to nonattainment in another state. In reaching this conclusion, the Court emphasized that EPA had not adequately measured each individual state's significant contribution. *See id.* at 908. ("It is unclear how EPA can assure that the trading programs it has designed in CAIR will achieve section 110(a)(2)(D)(i)(I)'s goals if we do not know what each upwind state's "significant contribution" is to another state.")

The Court also emphasized that section 110(a)(2)(D)(i)(I) "prohibits sources '*within the State*' from 'contribut[ing] significantly to nonattainment *in* * * * *any other State* * * *' " *Id.* at 907. (quoting section 110(a)(2)(D)(i)(I) and adding emphasis). While recognizing that it was "possible that CAIR would achieve section 110(a)(2)(D)(i)(I)'s goals" it concluded that "CAIR assures only that the entire region's significant contribution will be eliminated," and that "EPA is not exercising its section 110(a)(2)(D)(i)(I) duty unless it is promulgating a rule that achieves something measurable toward the goal of prohibiting sources "within the State" from contributing to nonattainment or interfering with maintenance "in any other State." *Id.* at 907. Furthermore, since CAIR was designed as a "complete remedy to section 110(a)(2)(D)(i)(I) problems" the Court emphasized that "it must actually require elimination of emissions from sources that contribute significantly and interfere with maintenance." *Id.* at 908. In doing so, however, the Court also acknowledged that it had accepted in *Michigan* v. *EPA*, 213 F.3d 663 (D.C. Cir. 2000) EPA's decision to apply uniform emissions controls and its consideration of cost in the definition of significant contribution. *See North Carolina*, 531 F.3d at 908.

In developing options to eliminate the emissions identified as constituting all or part of a state's significant contribution and interference with maintenance, EPA has been mindful of the direction provided by the Court. As discussed in greater detail later, EPA believes that each of the remedy options presented is consistent with the Court's opinions interpreting the requirements of section 110(a)(2)(D)(i)(I).

3. Remedy Options Overview

EPA is proposing one "remedy" option to implement the emissions reductions requirements and taking comment on two alternatives. This section provides a brief overview of the proposed remedy and the two alternatives. Sections V.D.4, V.D.5, and V.D.6, later, describe the proposed remedy and the alternatives in detail.

EPA considered a full range of remedy options in developing this proposal. Among other things, EPA considered variations of direct control options, intrastate cap and trade, interstate cap and trade, hybrids of these approaches, and simple state emissions caps. Stakeholders have suggested a variety of remedy options for EPA's consideration. A TSD in the docket entitled "Other Remedy Options Evaluated" describes other options that EPA evaluated.

Based on its consideration of a range of options, EPA is proposing one remedy option and requesting comment on two alternatives. The proposed remedy option, discussed later, is a hybrid approach that combines limited interstate trading with other requirements. The alternative remedies on which EPA requests comment include an intrastate trading option and a direct control option. The proposed and alternative remedy options would regulate SO_2 and NO_X emissions from EGUs through FIPs in the covered states to eliminate or address the states" significant contribution to nonattainment in, or interference with maintenance by, downwind areas with respect to the daily and annual $PM_{2.5}$ NAAQS and the 8-hour ozone NAAQS.

The remedy option EPA is proposing would use state-specific control budgets and allow for intrastate and limited interstate trading of emissions allowances allocated to EGUs. This approach would assure environmental results while providing some limited flexibility to covered sources consistent with the Court decision as described later. The approach would also help ease the transition for implementing agencies and covered sources from CAIR to the Transport Rule. Based on consideration of a range of options, EPA believes that the proposed option is the best approach, for the reasons discussed in section V.D.4.

The Agency is also presenting other alternative remedies for comment. The first alternative for which EPA requests comment would use state-specific control budgets and allow intrastate trading of emissions allowances allocated to EGUs, but no interstate trading. The second alternative for which EPA requests comment is a direct control program in combination with state-specific control budgets.

EPA recognizes there could be cost savings from an approach that uses aless restrictiveinterstate trading option. EPA also recognizes that unrestricted trading programs including the NO_X SIP Call Trading Program have been very successful in addressing regional pollution problems.

In this action, EPA is not proposing such an unrestricted trading program, because EPA does not believe that such an option could provide assurance that each state achieves emissions reductions within the state, as required by the *North Carolina* decision. As the D.C. Circuit emphasized in its opinion, the statutory requirement in section 110(a)(2)(D)(i)(I) aims to prohibit "sources "within the State" from contributing to nonattainment or interfering with maintenance in "any other State." *North Carolina*, 531 F.3d at 908. The location of emission reductions is relevant because it can influence where air quality improvements occur and whether a particular state meets its statutory obligations. See North Carolina, 531 F.3d at 907.

In addition to considering unrestricted trading, EPA also considered whether there were other ways that a trading program could be structured to address the Court's concerns. In particular, EPA reviewed a methodology that had been investigated during the development of the NO_X SIP Call regulation that used trading ratios ("Development and Evaluation of a Targeted Emission Reduction Scenario for NO_X Point Sources in the Eastern United States: An Application of the Regional Economic Model for Air Quality (REMAQ)", Prepared by Stratus Consulting inc. November 24, 1999) (at *http://www.epagov/airtransport*). This approach would allow interstate trading, but use trading ratios to take into account differences in the cumulative downwind impact of emissions from different states. Trading ratios would be developed for each pair of states using air quality modeling such that, given the meteorological assumptions underlying the air quality modeling, the ratios would represent the ratio of the benefit to downwind air quality within a region from controlling emissions in different upwind areas. For instance, in its simplest form, if emission reductions from State A were twice as effective at reducing cumulative downwind air quality impact on a set of downwind receptors as emission reductions from State B, the trading ratio between States A and B would be 2 to 1.[82] In other words, if the States chose to trade, State A would have to purchase 2 allocations from State B to cover 1 ton of State A's emissions, since State A's emissions have twice the impact on downwind air quality. Such an approach offers the very valuable potential to address the transport problem in an effective (and potentially less costly) manner, as it incentivizes reductions from the places where they have the greatest value in reducing downwind air quality problems. While it offers such opportunities, there are challenges in developing such a system that is consistent with the requirement under section 110(a)(2)(D) that emission reductions occur in particular geographic locations. The trading ratio approach would be designed to assure a cumulative downwind air quality result, not to assure specific upwind reductions. Although it would reduce the incentive for sources from upwind states with larger cumulative impacts to comply by purchasing allowances (since they would need to purchase a greater number of allowances per ton emitted than sources in states with less of an impact), as currently contemplated it would not be possible under this approach to include enforceable legal requirements to ensure that a specific state's emissions remain below a specified level or to ensure that a specific amount of reductions occur within a particular state. EPA specifically requests comment on whether a ratios trading program could be designed to provide such a legal assurance. We also seek comment on whether such an assurance would be needed if, for example, in practice modeling results predicted with confidence that sufficient state-by-state reductions would be achieved under such an approach.

In the SIP Call, EPA did not ultimately propose this methodology for several reasons. First, the Stratus Consulting study ("Development and Evaluation of a Targeted Emission Reduction Scenario for NO_X Point Sources in the Eastern United States: An Application of the Regional Economic Model for Air Quality (REMAQ)") estimated that the most significant cost savings occurred from moving from a uniform direct control approach to a conventional cap-and-trade approach (the study suggested that this would lead to cost savings of approximately 25 percent). Adding trading ratios added significant complexity while only very slightly lowering costs (1 percent to 5 percent compared to conventional cap and trade, where the cost savings decreased as the problem being addressed became more widespread (*e.g.* cost savings for the more stringent 1997 8 hour ozone NAAQS standard would be less than cost savings for the less stringent early 1 hour standard)) (Stratus, page s–2). However, because the transport rule is a larger program covering multiple pollutants with a different set of non-attainment areas and a broader geographic scope, there is the potential for greater cost savings. Second, the trading ratios are dependent upon the meteorological assumptions used to develop them; to the extent that future year meteorology or costs turn out to be different, the trading ratios could in fact lead to less than predicted downwind air quality benefits. Notably in reality, the ratios would have to consider that the upwind states that impact a downwind receptor vary from receptor to receptor; conversely each upwind state contributes to different sets of downwind receptors. It would be very challenging to develop trading ratios that account for this myriad of different relationships. EPA believes these concerns are also valid in the context of this Transport Rule.

In addition, in considering this approach in the original SIP Call, it took close to a year to perform the underlying analysis to develop ratios for 1 pollutant (NO_X) and one downwind air quality problem (ozone). In this context, there are 3 pollutants (annual NO_X, annual SO_2 and ozone season NO_X) and two downwind air quality problems (ozone and $PM_{2.5}$) to consider.

EPA requests comment on the trading ratios approach, including whether: The trading ratio approach described above would be consistent with the Court opinion in *North Carolina* v. *EPA* and satisfy the section 110(a)(2)(D) requirement that reductions occur "within the state"; there are ways the approach could be modified to be consistent with the Court opinion and the statutory requirement; there are ways that such an approach could administratively be put in place by 2012 and be modified and adopted if further reductions are required to address

[82] Note that the report evaluating this alternative was a theoretical economic and air quality analysis of the concept. It did not explore how trading ratios would be incorporated into a workable trading program. It did however indicates that the "approach also provides for the possibility that the emission weights developed by this analysis could be incorporated into an emission trading program in which emission weights act like exchange rates between different subregions and species. However this adds a significant increase in the complexity of the market and in practical terms is worth considering only when the potential cost savings are large enough to offset the additional complexity in market structure." P. 1–7, Stratus Consulting Inc. November 24, 1999.

future NAAQS; and on whether there are ways that such a system could be designed to be transparent and relatively simple for sources to understand and comply with.

Analysis from the SIP Call suggests that the trading ratios approach might have the potential to slightly reduce costs. However, the approach, as envisioned, appears to be in tension with EPA's mandate under section 110(a)(2)(D)(i)(I) to assure that significant contribution is fully addressed in each upwind state. While such an approach would ensure reductions on a region-wide basis, EPA has not been able to identify a way that the trading ratio approach could be modified to assure a specific set of downwind emissions reductions from all states. Under such an approach, there is the potential that some upwind states might make reductions that are larger than their significant contribution, while other states might make reductions that are less than their significant contribution. Because the state budgets have been designed to achieve all reductions available at a given cost, trading ratios other than one to one, although providing equivalent improvements in downwind air quality would lead to emissions reductions that were inconsistent with the initial budgets.[83]

Because EPA recognizes the potential cost savings and potential improvements in program effectiveness associated with less restricted trading options, EPA is also requesting comment on the appropriateness of the assurance provisions that have been proposed, including whether they are adequate to assure that significant contribution and interference with maintenance are addressed in each state, whether they are overly restrictive, and whether there are less restrictive options that would provide adequate assurance that the statutory mandate is satisfied while providing more flexibility. Alternative approaches could potentially include: Using the basic methodology proposed with a higher or lower variability limitation or using an alternative to the approach to assure that state emissions budgets are met (*e.g.*, trading ratios designed to assure that certain upwind emission reduction targets are met, rather than trading ratios designed to assure that downwind air quality goals are met). With regards to the variability limits that EPA has proposed, EPA takes comment on alternative approaches to calculating those limits, such as considering confidence intervals different than a 95 percent confidence interval such as a 99 percent confidence interval (For more information see TSD, "Power Sector Variability".)

EPA specifically requests that any commenter suggesting a less restrictive approach address how the commenter's preferred approach would satisfy the statutory mandate in section 110(a)(2)(D)(i)(I) of the Clean Air Act and be consistent with the decision of the DC Circuit in *North Carolina* v. *EPA*, 531 F.3d 8906 (2008) (*e.g.*, if commenters suggest a higher variability limitation, what would be the rationale for allowing that amount of variability; if commenters suggest an alternative framework, how would that framework assure that reductions occur "within the state") as well as how EPA could develop the approach in a way that would be workable for sources, states, and EPA in time to achieve emission reductions in 2012 (*e.g.*, would an approach with trading ratios impact transaction costs or be overly complex for less sophisticated trading entities, can the analysis needed to develop the approach be completed in a timely way).

As discussed in section IV.E, EPA is proposing new state budgets developed on a different basis from the CAIR budgets. The intrastate and interstate trading remedy options would use new allowance allocations, also developed on a different basis from the CAIR FIP allowance allocations. *See* section IV for the proposed state budget approach and section V.D.4 for proposed allowance allocation approaches.

As discussed in section IV.F, EPA believes that inherent variability in power system operations affects each state's baseline emissions and thus also affects a state's emissions after elimination of all significant contribution and interference with maintenance. Thus, emissions may vary somewhat after implementation of the remedies under consideration. This includes the proposed remedy option (State Budgets/Limited Trading), the intrastate trading alternative, and the direct control alternative. Sections V.D.4, V.D.5, and V.D.6 describe variability approaches for the proposed remedy and each of the alternative remedies.

EPA also considered only establishing state emissions caps. Such an approach would define what must be done to eliminate all (or in some cases part) of each state's significant contribution and interference with maintenance, but it would not implement specific requirements to eliminate those emissions. As described in section III.C in this preamble, EPA decided to implement the emission reduction requirements through FIPs. To do so, EPA recognized that it needed to do more than establish simple state emissions caps. For this reason, EPA rejected the simple state emission cap option.

As with any FIP that EPA issues, a covered state may submit, for review and approval, a state implementation plan (SIP) that replaces the Federal requirements with state requirements that would achieve the required reductions. A state's SIP submission to replace the Transport Rule FIP might propose to use any remedy of the state's choosing that actually eliminates the emissions that significantly contribute to nonattainment or interfere with maintenance downwind. Section VII in this preamble further discusses SIP submissions.

4. State Budgets/Limited Trading Proposed Remedy

In this action, EPA is proposing FIPs that would establish state-specific emission control requirements using state budgets starting in 2012 in 32 states.[84] This remedy option would allow unlimited intrastate trading and limited interstate trading to account for variability in the electricity sector, but also includes assurance provisions to ensure that the necessary emissions reductions occur within each covered state. The assurance provisions, described later in this section, would restrict EGU emissions within each state to the state's budget with the variability limit and would ensure that every state is making reductions to eliminate the portion of significant contribution and interference with maintenance that EPA has identified in today's action. EPA is proposing to impose these assurance provisions starting in 2014. State-specific emissions budgets with variability limits would be established as described in section IV in this preamble. These budgets without the variability limits would be used to determine the number of emissions allowances allocated to sources in each state: An EGU source would be required to hold one allowance for every ton of

[83] EPA, however, has proposed variability limits to these budgets, and it is possible a ratios approach may imply emissions would fall within the variability limits if the ratios ultimately turned out to be close to one-to-one.

[84] The 32 states are: Alabama, Arkansas, Connecticut, District of Columbia, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin. As noted in section III, for purposes of this rulemaking, when we discuss "states" we are also including the District of Columbia.

SO_2 and/or NO_X emitted during the compliance period. Banking of allowances for use in future years would be allowed under the proposed remedy. For the 2012–2013 transition period, EPA is proposing the State Budgets/Limited Trading remedy without assurance provisions. EPA is taking comment on all aspects of, as well as alternatives to, this option that address the requirements of 110(a)(2)(D)(i)(I) for prohibiting emissions that significantly contribute to or interfere with maintenance of the NAAQS in downwind states.

a. Description of the Proposal

The proposed FIPs would address the elimination of significant contribution and interference with maintenance by 2014. A first phase of reductions would be required by 2012 to assure that significant contribution and interference with maintenance are eliminated as expeditiously as practicable.

To directly eliminate the portion of each state's significant contribution and interference with maintenance that EPA has identified in this action, the proposed remedy utilizes the state budgets with variability limits described in section IV. The budgets without variability limits are used to determine the number of allowances issued to sources in each state. Each affected source must hold, and surrender to EPA, allowances equal to its emissions during the compliance period. In addition, assurance provisions under the proposed remedy cap each state's EGU emissions at a state-specific budget with a variability limit to ensure that every state actually reduces, within the state, all emissions necessary to eliminate the portion of its significant contribution and interference with maintenance that EPA has identified in today's proposal.

For the 2012–2013 transition period, EPA is taking comment on whether the assurance provisions used to limit interstate trading are needed, since the state-specific budgets are based on known air pollution controls and thus a high level of certainty exists about where reductions will occur. As described later, the proposed FIPs include penalty provisions that are adequate to ensure that the budget including a variability limit will not be exceeded so that each state eliminates the portion of its significant contribution and interference with maintenance that EPA has identified in today's proposed action.

The proposed remedy establishes four interstate trading programs starting in 2012: Two for annual SO_2, one for annual NO_X, and one for ozone season NO_X. One SO_2 trading program is for sources in states (referred to as the SO_2 group 1) that need to make more aggressive reductions to eliminate the portion of their significant contribution that EPA has identified in today's proposed action, while the second is for sources in states (referred to as SO_2 group 2) with less stringent reduction requirements. States within SO_2 group 1 can trade SO_2 allowances only with other states in that group. Similarly, states within SO_2 group 2 can trade SO_2 allowances only with other states in that group. Note that all states covered for annual NO_X may trade with each other, even if they are in different groups for SO_2. Table IV.D.5 in section IV, previously, summarizes the respective covered states for the SO_2 group 1, SO_2 group 2, and annual NO_X trading programs; Table IV.E–2 lists the states for the ozone season NO_X program.

New emissions allowances based on the new state budgets without variability would be allocated to individual sources, as described later. Four sets of allowances would be allocated, one for each of the four trading programs (SO_2 group 1, SO_2 group 2, NO_X annual, and NO_X ozone season). This allocation methodology neither uses heat input adjusted by fuel factors, nor relies on the allocation of allowances under Title IV of the Act.

Sources would be allowed to trade allowances. However, the assurance provisions would limit total emissions from each state, restricting the variability of emissions from any particular state to the variability associated with its baseline emissions prior to the elimination of all or part of the state's significant contribution or interference with maintenance.

Allowance banking is permitted. Banking (or saving) allowances for future use in any given year allows sources flexibility in compliance planning. Banking lowers costs and helps reduce market volatility. Banking also acts as an incentive to reduce emissions early and accumulate allowances that can be used for compliance in future periods. Because the early reductions encouraged by the ability to bank allowances would result in the reduction of emissions below allowable levels earlier than required, the environmental and human health benefits of the reductions would accrue sooner.

b. How the Proposal Would Be Implemented

(1) Applicability

The requirements in the proposed FIPs would apply to large EGUs. Specifically, a covered source would be any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion device, a generator with nameplate capacity of more than 25 MWe producing electricity for sale. The term "fossil fuel" is defined as including natural gas, petroleum, coal, or any form of fuel derived from such material. This is the same definition that was used in CAIR and would include all material derived from natural gas, petroleum, or coal, regardless of the purpose for which such material is derived. For example, with regard to consumer products that are made of materials derived from natural gas, petroleum, or coal, are used by consumers and then used as fuel, these materials in the consumer products would qualify as fossil fuel.

Certain cogeneration units or solid waste incinerators otherwise covered by this general category of covered units would be exempt from the FIP requirements. These proposed applicability requirements are essentially the same as those in the CAIR model trading rules and CAIR FIPs (reflecting the revised cogeneration unit definition promulgated in October 2007 (72 FR 59195; October 19, 2007)), with some technical corrections to the exemptions.

Cogeneration unit exemption. In order to meet the proposed definition of "cogeneration unit," a unit (*i.e.*, a boiler or combustion turbine) must operate as part of a "cogeneration system," which is defined as an integrated group of equipment at a source (including a boiler or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy. In order to qualify as a cogeneration unit, a unit also must meet, on an annual basis, specified efficiency and operating standards, *e.g.,* the useful power plus one-half of useful thermal energy output of the unit must equal no less than a certain percentage of the total energy input, useful thermal energy must be no less than a certain percentage of total energy output, and useful power must be no less than a certain percentage of total energy input. Total energy input includes all energy input except from biomass.

These proposed elements of the "cogeneration unit" definition are very similar to the definition used in CAIR. However, there are two technical differences. First, under the definition used in CAIR to qualify as a "cogeneration unit," a unit had to meet the efficiency and operating standards every year starting with the first 12-months during which the unit produced electricity. In contrast, under the definition proposed here, a unit can qualify as a "cogeneration unit" if it meets the efficiency and operating standards every year starting the later of November 15, 1990 or the date on which the unit first produces electricity. EPA believes this definition of "cogeneration unit" is preferable because it may be problematic to obtain sufficiently detailed information about unit efficiency and operations for some units (*e.g.*, old units that may have started producing electricity many years ago). This approach is also more consistent with the approach taken in the general applicability criteria. EPA requests comment on whether it may also be problematic to obtain sufficiently detailed information about unit efficiency and operation back to November 15, 1990 and whether the efficiency and operating standards should be limited to even more recent years by requiring that the standards be met every year starting the later of a date (*e.g.*, January 1) of a more recent year (*e.g.,* 2000, 2005, or 2009) or the date on which the unit first produces electricity. Second, in CAIR, each unit had to meet individually the efficiency standard (i.e., the requirement that useful thermal or electrical output be at least a specified percentage of energy input). In contrast, under the "cogeneration unit" definition proposed here, if the cogeneration system of which a topping-cycle unit (where power is produced first and then useful thermal energy is produced using the resulting waste energy) is a part meets the efficiency standard on a system-wide basis, then the unit is also deemed to meet that efficiency standard. EPA believes this definition is preferable because it addresses cases where one unit in a cogeneration system is operated at a lower efficiency (*e.g.*, as a "swing" unit whose use varies with demand) to allow the rest of the units in the cogeneration system to operate with higher efficiency. EPA requests comment on whether this approach should also be applied to bottoming-cycle units (where useful thermal energy is produced first and then useful power is produced using the resulting waste energy).

As discussed previously, the operating and efficiency standards in the "cogeneration" definition must be met every year. However, EPA is concerned whether these annual standards should be applied to a calendar year when the unit involved did not operate at all. For such a year, the unit would be unable to meet the operating and efficiency standards but also would not have any emissions. EPA therefore requests comment on whether it should exclude, from the requirement to meet the operating and efficiency standards, calendar years (if any) during which a unit does not operate at all.

If a unit meets the definition of cogeneration unit (including the efficiency and operating standards), then it may qualify for the proposed cogeneration unit exemption depending on whether it meets additional criteria concerning the amount of electricity sales from the unit. In order to qualify for the exemption, a cogeneration unit would need to supply in any calendar year—starting the later of November 15, 1990 or the start-up of the unit's combustion chamber—no more than one-third of its potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. EPA requests comment on whether it may be problematic to obtain sufficiently detailed information about the disposition of a unit's generation (*e.g.*, how much was used on site or by an industrial host and how much was supplied to a utility distribution system for sale) back to November 15, 1990 and whether the electricity sales limit should be restricted to more recent years by requiring that the limit be met every year starting the later of a date (*e.g.*, January 1) of a more recent year (*e.g.*, 2000, 2005, or 2009) or the start-up of a unit's combustion chamber.

Solid waste incineration unit exemption. The proposed FIPs also include an exemption for solid waste incineration units commencing operation before January 1, 1985, for which the average annual fuel consumption of non-fossil fuels during 1985–1987 exceeded 80 percent and, during any three consecutive calendar years after 1990, the average annual fuel consumption of non-fossil fuels exceeds 80 percent, on a Btu basis. With regard to a solid waste incineration unit commencing operation on or after January 1, 1985, EPA proposes that the unit would be exempt if its average annual fuel consumption of non-fossil fuel for the first 3 calendar years of operation and for any 3 consecutive calendar years, thereafter, does not exceed 80 percent. This is the same as the solid waste incineration unit exemption used in CAIR. EPA requests comment on whether it may be problematic to obtain sufficiently detailed information about unit operation potentially as far back as 1985–1987 and 1990 and whether the fuel consumption standard for each unit should be limited to more recent years by requiring that the standard be met every year starting the later of a date (*e.g.*, January 1) of a more recent year (*e.g.*, 2000, 2005, or 2009) or the date on which the unit first produces electricity.

Further, analogous to the approach proposed for the cogeneration unit exemption, the proposed solid waste incineration unit exemption would apply to units that qualify as solid waste incineration units every year starting the later of November 15, 1990 or the date the unit first produces electricity. EPA requests comment on whether it may be problematic to obtain sufficiently detailed information about whether a unit qualified as a solid waste incineration unit back to November 15, 1990 and whether the qualification requirement should be restricted to more recent years by imposing the qualification requirement every year starting the later of a date (*e.g.*, January 1) of a more recent year (*e.g.*, 2000, 2005, or 2009) or the date of unit first produces electricity.

EPA also proposes to make explicit in the FIPs an interpretation that the Agency adopted in applying CAIR, namely that—solely for purposes of applying the fossil-fuel use limitation in the solid waste incineration unit exemption—the term "fossil fuel" is limited to natural gas, petroleum, coal, or any form of fuel derived from such material "for the purpose of creating useful heat." For example, this means that consumer products made from natural gas, petroleum, or coal are not fossil fuel, for purposes of determining qualification under the limitation on fossil-fuel use, because the products (*e.g.*, tires) were derived from natural gas, petroleum, or coal in order to meet certain consumer needs (*e.g.*, to meet transportation needs), not in order to create fuel (*i.e.*, material that would be combusted to produce useful heat).

Opt-in units. EPA proposes to include, in the trading programs under the proposed FIP, provisions allowing non-electric generating (non-covered) units to opt into one or more of the proposed trading programs. EPA is proposing opt-in provisions since they could encourage emission reductions by sources that could make lower cost emissions reductions than electric generating units. These lower cost reductions could replace higher cost reductions that would otherwise be required by some electric generating units and could reduce overall program costs.

Specifically, the proposed opt-in provisions would allow a non-covered unit to enter a proposed trading program voluntarily and obtain an allocation of allowances reflecting the unit's emissions before opting in. Once in the program, the unit could make emissions reductions at a lower cost than other units in the program and then sell, to covered sources for use in compliance, allocated allowances that are in excess of the unit's reduced emissions. The allowances created for and allocated to the opt-in unit would be in addition to the allowances issued from the state budget and would be usable in compliance by any covered unit (or opt-in unit) just like the allowances allocated from the state budget to covered sources. Replacing higher cost reductions by covered units by lower cost reductions by opt-in units could reduce the overall cost of controlling emissions. EPA requests comment on the benefits and concerns of including opt-in provisions.

The proposed opt-in provisions would establish the following procedures, which are similar to those set forth in the CAIR FIPs. A unit would be eligible to opt into one of the proposed trading programs if the unit: (1) Is an operating boiler, combustion turbine, or other stationary combustion device; (2) is in a facility that is located in a state subject to that proposed trading program; (3) vents all its emissions through a stack or duct; and (4) would be able to meet the monitoring, reporting, and recordkeeping requirements for covered units under the proposed trading program. The owners and operators, through a designated representative, of a source with a unit seeking to opt in would submit to EPA an opt-in application, which must include an emissions monitoring plan for the unit. If EPA approved the monitoring plan, the unit would operate, monitor, and report emissions in accordance with the monitoring plan and monitoring and reporting requirements under Part 75, for at least one or for up to 3 full calendar years (or full ozone seasons, in the case of an opt-in unit in the proposed NO_X ozone season trading program). The unit's monitored heat input and emissions rate for that period would be the baseline heat input and baseline emissions rate used in calculating any future opt-in allowance allocations.

After the monitoring period, EPA would review the opt-in application and either approve the application (including an allowance allocation for the first year of approved opt-in status), effective January 1 (May 1 for the NO_X ozone season program) of the year of the approval, or disapprove the application. By December 1 (September 1 for the NO_X ozone season program) of the first year and each subsequent year, EPA would calculate and record the opt-in unit's allowance allocation for the year. The allowance allocation for the year involved would be the product of: The lesser of the baseline heat input and the opt-in unit's actual heat input during the control period in the immediately preceding year; and the lesser of the baseline emissions rate multiplied by 70 percent and the most stringent state or federal emissions limitation applicable to the unit (or emissions levels resulting from the imposition of Clean Air Act requirements) any time during the control period in the year involved.

After the opt-in unit was in the program for at least four years, the owners and operators could request to withdraw the opt-in unit at the end of a control period if the unit met the requirement to hold allowances covering emissions for that control period and if any allowances already allocated for a subsequent control period were surrendered. However, the owners and operators could not submit a new opt-in application for the withdrawn unit until at least 4 years after the last control period before the withdrawal. An opt-in unit that had a change in regulatory status during a control period and would then meet the general applicability requirements for covered units would immediately lose its status as an opt-in unit. Having lost its opt-in unit status, the unit would have to surrender to EPA the allocated opt-in allowances attributable to the portion of any control period during which the unit no longer qualified as an opt-in unit.

In addition to a general request for comment on all aspects of this opt-in requirement, EPA requests comment on three specific aspects of the proposed opt-in provisions. First, EPA requests commenters to explain how much interest they believe owners and operators of noncovered sources would have in using these proposed provisions to opt into one or more of the proposed trading programs and what types of sources would be most likely to opt in. Commenters on this aspect of the proposed provisions should consider what effect (if any) future emission reduction requirements under upcoming, new regulations (*e.g.*, regulations concerning maximum available control technology (MACT) standards for sources such as industrial boilers and cement kilns, best available retrofit technology (BART) requirements for certain stationary source categories, and reasonably available control technology (RACT)) might have on the pool of sources that might be interested in opting into the program. EPA notes that, in the Acid Rain Program, opt-in provisions were established in section 410 of the Act, were implemented in the Acid Rain Program regulations starting in 1995, and, to date, have been used by 4 facilities (plus 2 more facilities that temporarily opted in to obtain allowances for use in the CAIR SO_2 trading program). In the NO_X Budget Trading Program, EPA promulgated opt-in provisions that states could include in their SIPs and that were used by 3 facilities.

Second, EPA requests comment on whether it is necessary to take steps to identify in this application process whether emissions reductions identified by these facilities are reductions units would not have made for other reasons unrelated to the opt in. Comments on this issue would be especially useful if they discussed how the proposed opt-in provisions could be revised in order to ensure that opt-in units would not be credited for emissions reductions that the units would make even if they did not opt in. For example, a unit that, for business or other reasons, was already planning to take actions that would have the effect of reducing emissions (*e.g.*, fuel switching) may be able to opt in under this proposed approach and obtain allowance allocations that could be sold to covered units. In that case, emissions reductions that would have occurred anyway would be offset by the allocation of new, opt-in allowances that would be in addition to the state budget. The net result, in that case, would be an increase in total emissions—considering the emissions of both the covered units and the opt-in unit—over what total emissions would have been if the unit had not opted in. EPA requests comment on whether, in that circumstance the total emissions reduction still may be sufficient to satisfy the interstate transport issue if such reductions were not anticipated in state budgets. In other words, even if emissions reductions would have happened in the absence of the program, they may still be reductions that alleviate attainment or maintenance issues in downwind states. Third, EPA requests comment on whether the baseline emission rate used to determine the allocations for each opt-in unit should be multiplied by 70 percent before EPA compares that rate to the unit's most stringent applicable emissions limitation in order to determine which is lower. The lower emission rate would then be used in calculating the opt-in unit's allocation. EPA also requests comment on whether the allocation for an opt-in unit during Phase II of the proposed SO_2 Group 1 trading program should be reduced by 45 percent, reflecting the average percent reduction in state SO_2 Group 1 budgets from Phase I to Phase II. The 70 percent reduction of the baseline emission rate for all opt-in units, and the further 45 percent reduction in Phase II allocations for SO_2 Group 1 opt-in units, would be meant to ensure that opt-in facilities install controls in a similar manner as covered units; however, all things equal, this may serve to lower the number of facilities that would opt into the program. EPA therefore specifically solicits comment on whether the proposed 70 percent reduction (or some other percentage reduction or no reduction) should applied to the baseline emission rate for all opt-in units and on whether any additional percentage reduction or 45 percent or some other additional percentage reduction should be applied to SO_2 Group 1 opt-in units on Phase II in order to strike a reasonable balance between achieving additional reductions per opt-in facility and having more facilities opt in.

Sources equal to or less than 25 MWe and Non-EGUs. Certain smaller EGUs and non-EGU sources that were included in the NO_X Budget Trading Program were brought into the CAIR NO_X ozone season trading program. For treatment of such sources in the proposed FIPs, see section V.F in this preamble.

In the Northeast, a large number of EGUs serving generators with a nameplate capacity equal to or less than 25 MWe contribute NO_X emissions to ozone problems on high electric demand days. There is regional interest in lowering the 25 MWe applicability threshold in the ozone season to deal with this issue and in potentially requiring these units to operate with greater controls than a trading program would necessitate. EPA requests comment on lowering the greater-than-25 MWe applicability threshold for EGUs during the ozone season, and whether a trading program offers the right approach for addressing NO_X emissions from these smaller EGUs.

(2) Allocation of Emissions Allowances

EPA proposes to distribute, to sources in each state, a number of emissions allowances equal to the SO_2, annual NO_X, and ozone-season emissions budgets for that state identified in section IV.E (the state budgets listed in IV.E are the budgets without accounting for variability). As discussed later, EPA proposes to set aside 3 percent of each state's emissions budgets for new units. Tables IV.E.–1 and IV.E.–2 in section IV.E, referenced previously, show the permanent SO_2, NO_X, and ozone season NO_X budgets for each covered state (without accounting for variability). EPA would distribute four discrete types of emissions allowances for four separate cap and trade programs: SO_2 group 1 allowances, SO_2 group 2 allowances, NO_X annual allowances, and NO_X ozone season allowances.

In the SO_2 group 1 and SO_2 group 2 programs, each SO_2 allowance would authorize the emission of one ton of SO_2 annually. In the NO_X annual program, each NO_X annual allowance would authorize the emission of one ton of NO_X annually. In the NO_X ozone season program, each NO_X ozone season allowance would authorize the emission of one ton of NO_X during the regulatory ozone season (May through September for this proposed rule). Note that, as explained in section IV.E, EPA is taking comment on extending the ozone season for this rule.

In each of the four trading programs, a covered source would be required to hold sufficient allowances to cover the emissions from all covered units at the source during the control period. EPA proposes to assess compliance with these allowance-holding requirements at the source (*i.e.*, facility) level.

This section explains how EPA proposes to allocate to two sets of units in a state, existing units and new units. This section also describes the new unit set asides in each state, allocations to units that are not operating, and the recording of allowance allocations in facility accounts.

EPA proposes to base allocations to existing units on projected emissions from these units after elimination of some or all significant contribution and interference with maintenance (*i.e.*, projected emissions after implementation of the proposed FIPs), and after deductions for the new unit set asides. Section IV.E describes how EPA developed the overall state budgets.

EPA requests comment on all aspects of the allocation method, such as the overall state budgets, the need to have existing unit and new unit allowance allocations, the proposed allocation methodology for existing units, and the proposed allocation methodology for new units. EPA believes the proposed approach is consistent at the state budget and unit level with the Court's direction and also addresses the new unit issue. The proposed methodology for allocating allowances does not consider heat input or fuel adjustment factors. Note that in light of the Court decision, EPA also is not proposing any allocation methodologies that rely on Title IV existing allowances.

EPA requests comment on whether there are alternative allocation methods EPA should consider that are consistent with the Court decision. EPA asks that commenters present any such approaches in detail to enable thorough evaluation and that they provide a legal analysis demonstrating how the approach is consistent with the Court's opinions and the statutory mandate of section 110(a)(2)(D).

Allocations to existing units. Existing units are units, as described in the Applicability section, previously (*see* 4.b), that commenced commercial operation, or are planned [85] to commence commercial operation, prior to January 1, 2012. EPA proposes that, for 2012, each existing unit in a given state receives allowances commensurate with the unit's emissions reflected in whichever total emissions amount is lower for the state, 2009 emissions or 2012 base case emissions projections. In either case, the allocation is adjusted downward, if the unit has additional pollution controls projected to be online by 2012. EPA proposes to use this same method to allocate allowances for each of the four trading programs (SO_2 group 1, SO_2 group 2, NO_X annual, and NO_X ozone season). This proposed allocation method is different from the allocation method used in the CAIR.

For states with lower SO_2 budgets in 2014 (SO_2 group 1 states), each unit's allocation for 2014 and later is determined in proportion to its share of the 2014 state budget, as projected by IPM. This approach is also different from the allocation method in CAIR. Further details on the proposed allocation method for existing units can be found in the "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD in the docket for this rule.

The proposed FIPs are designed to remove emissions from each upwind state that significantly contributes to nonattainment or interferes with maintenance downwind. The allocation method is consistent with the proposed approach for determining each upwind state's significant contribution and interference with maintenance (described in section IV) because the allocations would be based on the projected remaining emissions from each covered source in each upwind state after removal of the state's significant contribution and interference with maintenance.

EPA proposes to allocate to existing units one time, before the Transport

[85] Planned units, as identified in the EGU inventory and included in IPM modeling projections, comprise units that had broken ground or secured financing and were expected to be online by the end of 2011.

Rule cap and trade programs commence (*see* discussion of schedule, later). The allocations generally would be permanent (with the exception of non-operating units, discussed later) as base amounts and would not be updated. (Note that any unused new source set aside allowances would be distributed proportionally to existing units in addition to the base amount.) By not updating the allocations, EPA can allocate for several years at once, which supports the development of allowance trading markets.

The proposed unit-level allocations for existing EGUs for Phases I and II are set forth in the "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD in the docket for this rule, but EPA proposes to include them in the final rule in an Appendix A to each set of trading program regulations (*i.e.*, the SO_2 group 1, SO_2 group 2, NO_X annual, and NO_X ozone season trading programs). Because the TSD shows the proposed allocations, Appendices A in the proposed trading program regulations do not repeat the allocations and are simply reserved. The only circumstances under which allocations would not be permanent as base amounts would be if the unit in the Appendix A table turned out not to be a covered unit, or turned out not to be required to hold allowances to cover emissions, as of the first day of the control period in 2012,[86] or if the unit stops operating for three consecutive years.

Allocations to new units. EPA proposes to allocate emissions allowances to new units from new unit set-asides in each state. EPA proposes, for each of the four trading programs, to define a new unit as: Any covered EGU not listed in the table in Appendix A of the trading rule applicable to that program; any unit listed in Appendix A whose allocation is subject to the requirement that the Administrator not record the allocation or that the Administrator deduct the amount of the allocation (*see* previous discussion in footnote), or any unit listed in Appendix A that stopped operating for three consecutive years, is no longer allocated allowances as an existing unit, but resumes operation.

EPA believes it is important to have a small new unit set-aside in each state to cover new units within the budget that was set aside to address the state's significant contribution and interference with maintenance. To create new unit set-asides, EPA would distribute to existing EGUs a quantity of allowances less than the entire state emissions budgets. EPA would hold back, for the new unit set-aside for a state, 3 percent of the state budget. Three percent was established based on the total amount of new unit emissions projected for all the covered states (See "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD). In this way, new units could be allocated some allowances for their emissions, which are part of the the state's contribution to downwind nonattainment or interference with maintenance.

For every control period after the control period in which a new unit commences commercial operation or, in the case of an existing unit that did not operate for three consecutive years, resumes operation, EPA would allocate to the unit from the new unit set-asides based on the unit's reported emissions from the previous control period. EPA would not allocate to a new unit for the control period during which the unit commences commercial operation because the unit would have no actual emissions data on which to base such an allocation.

EPA proposes that, for the first control period for which the new unit wants an allowance allocation from the new unit set aside (after the first year of operation), the designated representative of the source that includes the new unit would submit to EPA a request for a new unit allocation.

For each control period, any allowances remaining in a state's new unit set-aside (after allocations are made to new units that requested allowances) would be distributed to the existing units in that state in proportion to the existing unit's original allocations. This ensures that total allocations to units in the state would equal the state budget.

For each control period, if the size of the new unit set-aside were insufficient to provide allocations for all new units requesting allowances, then allocations to all new units would be proportionally reduced.

EPA requests comment on the proposed allocation approach for new units. EPA also requests comment on alternative allocation approaches that would provide allowances to new units for the control period during which the unit commences commercial operation.

Size of new unit set asides. EPA proposes new unit set-asides that are 3 percent of the state emissions budgets. The size of the new unit set-aside would be 3 percent for the SO_2 group 1, SO_2 group 2, NO_X annual, and NO_X ozone season trading programs, as appropriate, for each state. EPA based the size of the proposed new unit set-asides on a comparison of projected emissions from new units to projected emissions from existing units for all covered states under the proposed State Budgets/Limited Trading remedy. As noted previously, EPA proposes that after a unit is not operating for three consecutive years, the allowances that would otherwise have been allocated to that unit, starting in the seventh year after the first year of non-operation, would be allocated to the new unit set-aside for the state in which the retired unit is located. This approach would allow the size of the new unit set-asides to grow over time. Note that in EPA's analysis to determine the size of the new unit set-asides, EPA assumed that allocations for non-operating units would be allocated to the new unit set-asides after a unit had ceased operating for 3 consecutive years (see "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD). EPA requests comment on the size of the new unit set-asides.

Non-operating units. EPA proposes that, once an EGU does not operate (*i.e.*, does not combust any fuel) for 3 consecutive years, the Agency would no longer allocate allowances to the unit, starting in the seventh year after the first year of non-operation. All allowances that would otherwise have been allocated to the unit for that seventh year and every year thereafter would be allocated to the new unit set-aside for the state in which the non-operating unit is located. This would provide additional allowances for new units that may need them (*e.g.*, for new units that replace non-operating units), and reflects the fact that new unit emissions are included in the state's budget that eliminates the portion of significant contribution and interference with maintenance that EPA has identified in today's proposed action (in an average year).

EPA proposes to continue allocating allowances to non-operating units during the 3 consecutive years of non-operation plus an additional 3-year period to reduce the incentive for owners to keep units operating simply to avoid losing the allowance allocations for those units. Other options that EPA considered include continuing to allocate allowances for an unlimited period of time, or

[86] If a unit was allocated allowances but turned out not to be a covered unit or turned out not to be required to hold allowances as of January 1, 2012, then the treatment of the allocation depends on when the Administrator determines the unit is not subject to the trading program or to the allowance-holding requirement. For instance, if the allocation has not been recorded, the Administrator would not record it, and, if the allocation has been recorded and the Administrator has not completed the compliance determination process for the unit, allowances equal to the allocation would be deducted from the unit's compliance account.

immediately discontinuing allocations to such units upon the unit ceasing operation.

Continuing allocations to non-operating units has the benefit of reducing the incentive to keep units in operation that should otherwise be, for instance, permanently retired due to age and inefficiency. EPA believes there will be less incentive to continue running old, inefficient EGUs if at least some allowances would still be received after retirement. On the other hand, stopping allocations for non-operating units realigns allowance allocations with the sources that actually need such allowances. Non-operating units obviously are no longer emitting and so do not need allowances. Moreover, additional allowances may be needed for the new unit set-aside to accommodate new units coming on line in the future. Allocating allowances for a specified, but limited, period after the unit ceases operating for 3 consecutive years, as EPA proposes to do, would be a middle ground approach to this issue.

EPA requests comment on the proposed approach for allocating allowances to non-operating units. EPA requests comment on simplifying allocations by not allocating at all to non-operating units. EPA also requests comment on maintaining perpetual allocations to non-operating units, similar to the treatment of non-operating units in the title IV Acid Rain Program.

Schedule for determining and recording allowances. As discussed previously, proposed allocations for existing units are shown in the "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD. EPA proposes to include final allocations for existing units in the Appendix A for each proposed trading program in the final Transport Rule.

EPA proposes to record initial allowances for existing units in facility accounts by September 1, 2011, for the control periods in 2012, 2013, and 2014. EPA proposes to record allowances for existing units by July 1, 2012 and July 1 of each year thereafter, for the control periods in the third year after the year the allowances are recorded. For example, EPA would record existing unit allowances by July 1, 2012 for control periods in 2015. Recording allowances several years in advance supports the development of the allowance trading markets and provides time for covered sources to plan for compliance.

As discussed previously, EPA proposes to determine allocations to a new unit based on the unit's reported emissions the prior year. Although the last quarter of emissions data for a year must be submitted to EPA in the fourth quarterly emissions report by January 30 of the next year, the emissions data in that report may be revised based on EPA's review and may not be finalized until May or June after receipt of that report. Consequently, EPA proposes to determine new unit allocations by July 1 of the year for which the allocation is determined. (Because, for an ozone season ending September 30, emissions data may not be finalized until the following February or March, EPA proposes to determine new unit allocations by April 1.) For example, EPA would determine a new unit's allocations for control periods in 2012 by July 1, 2012. EPA proposes to make the new unit allocation determinations available to the public through a notice of data availability. Under the proposal, objections to the notice could be submitted, and EPA would issue a second notice of data availability referencing any necessary adjustments of the new unit allocations.

EPA proposes to record allowances for new units by September 1, 2012 and September 1 of each year thereafter, for the control periods in the year that the allowances are recorded. (For the units in the NO_X ozone season program, the comparable deadline for recordation of new units" allowances is June 1.) For example, EPA would record new unit allocations by September 1, 2012 for control periods in 2012.

EPA requests comment on the proposed schedule for determining and recording emissions allowances, especially administratively-practical ways to record allowances as soon as possible, so facilities have information useful in compliance planning.

Alternative allocation methods. The proposed allocation method, described previously, would determine each unit's allocation consistent with the proposed approach to determine each state's significant contribution and interference with maintenance. EPA considered other alternative allocation methods. One is discussed here, but EPA recognizes that there are many ways that allowances could be allocated. EPA is requesting comment on whether the alternative described here or any other approach should be used instead of the proposed allocation method.

As discussed in section IV, the state emissions budgets are determined based on EPA's analysis of significant contribution and interference with maintenance in each upwind state. EPA believes that it is appropriate to develop individual unit allowances consistent with this approach. In the proposed approach, EPA does this by allocating down to the individual unit level using all of the same assumptions used in developing the proposed budgets. Under this approach all units are allocated allowances consistent with their projected emissions; this means that a unit that installs control equipment receives fewer allowances than a similar unit that did not install control equipment.

EPA is taking comment on an alternative methodology that still links unit allowances directly to the way state budgets were developed (and thus, significant contribution was defined). In the alternative, all units within a state would be treated as a single group. The allocation method would distribute allowances equal to a state's emissions budget without variability to each covered source in the state (in effect, distributing the responsibility for eliminating significant contribution and interference with maintenance) based on each source's proportional share of total state heat input. The state heat input would be as projected for the initial year of the program. In other words, this alternative method for distributing allowances would have the effect of distributing the responsibility for eliminating all or part of a state's overall significant contribution and interference with maintenance to individual units based on each unit's share of projected heat input.

There are other approaches to allocation. For example, EPA could identify groups of units in each state that are capable of having similar emissions characteristics (e.g., grouped by size, fuel type, or age). EPA would distribute a state's emissions budget without variability to each group of units in the state (in effect, distributing the responsibility for eliminating all or part of significant contribution) perhaps based on each group's proportional share of the state budget as projected in the initial year of the program. After apportioning a state's budget to the groups of units, under such an approach EPA could distribute allocations to individual sources within each group based on each source's proportional share of projected heat input. Like the first alternative allocation method described previously, this approach distributes each state's significant contribution and interference with maintenance to individual sources in the state. By determining groups and then distributing allocations within the groups based on proportional shares, this approach would treat units within the categories equally (*i.e.*, it would not treat a source that had acted early to control differently from one that had yet to take control action).

EPA requests comment on the proposed allocation approach, the alternative approach, and on any other approaches that are consistent with the Court decision. EPA asks that commenters present any such approaches in detail to enable thorough evaluation and that they provide a legal analysis demonstrating how the approach is consistent with the Court's opinions and the statutory mandate of section 110(a)(2)(D).

(3) Allowance Management System

EPA proposes that the State Budgets/Limited Trading remedy include an allowance management system (AMS) operated essentially the same as the existing allowance management systems that are currently in use for CAIR and the Acid Rain Program under Title IV. Under the proposed State Budgets/Limited Trading remedy, the SO_2 programs and the NO_X programs would remain separate trading programs maintained in EPA's existing AMS. AMS would be used to track Transport Rule trading program SO_2 and NO_X allowances held by covered sources, as well as such allowances held by other entities or individuals. Specifically, AMS would track the allocation of all SO_2 and NO_X allowances, holdings of SO_2 and NO_X allowances in compliance accounts (*i.e.*, accounts for individual covered sources) and general accounts (*i.e.*, accounts for other entities such as companies and brokers), deduction of SO_2 and NO_X allowances for compliance purposes, and transfers of allowances between accounts. The primary role of AMS is to provide an efficient, automated means for covered sources to comply, and for EPA to determine whether covered sources are complying, with the emissions rate limitations and other emissions-related provisions of the cap and trade programs. AMS also allows the public to see whether sources are complying. In addition, AMS provides data to the allowance market, including a record of ownership of allowances, dates of allowance transfers, buyer and seller information, and the serial numbers of allowances transferred.

(4) Monitoring and Reporting

EPA proposes to require that Transport Rule-covered sources monitor and report SO_2 and NO_X emissions in accordance with 40 CFR part 75. Most sources that would be covered by the proposed Transport Rule are already measuring and reporting SO_2 mass emissions year round under CAIR and/or the Title IV Acid Rain Program. Similarly, most sources that would be covered are already measuring and reporting NO_X mass emissions year round under CAIR. CAIR and the Acid Rain Program both require Part 75 monitoring.

Consistent, complete, and accurate measurement of emissions, as Part 75 requires, ensures that, for a given pollutant, one ton of reported emissions from one source is equivalent to one ton of reported emissions from another source. Thus, each allowance represents one ton of emissions, regardless of the source for which the emissions are measured and reported. This establishes the integrity of each allowance, which instills confidence in the underlying market mechanisms that are central to providing sources with flexibility in achieving compliance.

EPA proposes to require monitoring of SO_2 and NO_X emissions by all existing covered sources by January 1, 2012 for states covered for the daily and/or annual $PM_{2.5}$ NAAQS, and monitoring of NO_X emissions by May 1, 2012 for sources covered for the 8-hour ozone NAAQS, using Part 75 certified monitoring methodologies. New sources would have separate deadlines based upon the date of commencement of commercial operation, consistent with CAIR and the Acid Rain Program.

Specifically, a new unit must install and certify its monitoring system within 180 days of the commencement of commercial operation. While, under the Acid Rain Program and CAIR, the deadline was the earlier of 90 operating days or 180 calendar days after commencement of commercial operation, EPA intends to propose that part 75 be revised to use only the 180-day deadline. EPA believes that using only the 180-day deadline would ensure that new units have sufficient time to complete installation and certification of monitoring systems without having to request extensions of time and would facilitate compliance by making the monitoring deadline clearer for owners and operators and easier for EPA to apply. *See* a discussion on units transitioning from CAIR and units previously not covered by Part 75 requirements in section V.F, later.

EPA also proposes to require designated representatives to submit quarterly reports that would include emissions and related data and proposes to establish a procedure for resubmission of quarterly reports where appropriate. Specifically, the proposed reporting provisions would include the same requirement to submit quarterly reports as the requirement in Part 75. In addition, the proposed provisions would include language that would make explicit a process that is implicit under, and has been in continuous use in, the Acid Rain, NO_X Budget, and CAIR trading programs. The resubmission process would be as follows. The Administrator could review and audit any quarterly report to determine whether the report met the monitoring, reporting, and recordkeeping requirements in the proposed rule and Part 75. The Administrator would provide notification to the designated representative stating whether any of these requirements was not met and specifying any corrections that the Administrator believed were necessary to make through resubmission of the report and a reasonable deadline for a response. The Administrator could provide reasonable extensions of such deadline. The designated representative would be required, within the deadline (including any extensions), to resubmit the report with the identified corrections, except to the extent the designated representative would submit information showing that a correction was not necessary because the report already met the monitoring, reporting, and recordkeeping requirements relevant to the correction. Any resubmission of a quarterly report would have to meet the requirements for quarterly report submission, except for the deadline for initial submission of quarterly reports.

(5) Assurance Provisions

To ensure that the proposed FIPs require the elimination of all emissions that EPA has identified that significantly contribute to nonattainment or interfere with maintenance within each individual state, we are proposing to establish assurance provisions, as described later, in addition to the requirement that sources hold allowances sufficient to cover their emissions. These assurance provisions limit emissions from each state to an amount equal to that state's budget with the variability limit for state budgets, discussed in section IV. As described therein, this variability limit takes into account the inherent variability in baseline EGU emissions and recognizes that state emissions may vary somewhat after all significant contribution is eliminated. This approach also provides sources with flexibility to manage growth and electric reliability requirements, thereby ensuring the country's electric demand will be met while meeting the statutory requirement of eliminating significant contribution.

Starting in 2014, EPA is proposing as part of the FIPs to establish limits on the total emissions that may be emitted from EGUs at sources in each state. For any single year, the state's emissions must not exceed the state budget with the variability limit allowed for any single year for that state (*i.e.*, the state's 1-year variability limit). In addition, the 3-year rolling average of the state's emissions must not exceed the state budget with the variability limit allowed on average for any consecutive 3 years for that state (*i.e.*, the state's 3-year variability limit). Note that in 2014 and 2015, EPA would apply only the 1-year variability limit, and not the 3-year variability limit. Because emissions would be evaluated against the 3-year variability limit on a 3-year rolling average basis, the application of the 3-year variability limit in 2016 would serve to limit emissions in 2014 and 2015.

In other words, in addition to covered sources being required to hold allowances sufficient to cover their emissions, the total sum of EGU emissions in a particular state cannot exceed the state budget with the state's 1-year variability limit in any one year, and the state's annual average emissions for any 3-year period can not exceed, on average, the state budget with the state's 3-year variability limit. The fact of the 3-year variability limit would further assure that emissions are constrained during the two preceding years.

For example, a hypothetical state has a budget of 100,000 tons, a 1-year variability limit of 10,000 tons, and a 3-year variability limit of 5,800 tons.

- In the first year, collective emissions from covered EGUs in the state are 120,000 tons, 10,000 tons over the budget with 1-year variability limit of 110,000 tons, triggering the assurance provisions in that year.
- In the second year, collective emissions from covered EGUs in the state are 97,500 tons, below the state budget with 1-year variability limit of 110,000 tons. Assurance provisions are not triggered.
- In the third year, collective emissions from covered EGUs in the state are 109,000 tons, below the state budget with 1-year variability limit of 110,000 tons. Assurance provisions are not triggered for the 1-year variability limit. But after three years, the state emissions are computed against the 3-year variability limit. The 3-year rolling average (adding the last 3 years of emissions and dividing that by three) computes to 108,833 and determines that the 3-year variability limit of 105,800 tons is exceeded, even though in any one year, the 1-year variability limit may not have been exceeded.
- In the fourth year, collective emissions from covered EGUs in the state are 99,000 tons, below the state budget with 1-year variability limit of 110,000 tons. Assurance provisions are not triggered for the 1-year variability limit. The 3-year rolling average of the last 3 years is 101,833, which is less than the 3-year variability limit of 105,800. Assurance provisions are not triggered for the 3-year variability limit.

The variability limits for each state are shown in Tables IV.F–1 through IV.F–3 in section IV. The basis for the variability limits is also described in section IV.F. Additional details may be found in the "Power Sector Variability" TSD in the docket to this rule.

To implement this requirement, EPA would first evaluate whether any state's total EGU emissions in a control period exceeded the state's budget with 1-year variability limit. Next, EPA would evaluate whether any state's total EGU emissions in a control period exceeded the state's budget with the 3-year variability limit (once the program is in effect for 3 years, and each year thereafter). If any state's EGU emissions in a control period exceeded either of these limits, then EPA would apply additional criteria to determine which source owners in the state would be subject to an allowance surrender requirement. The proposed allowance surrender requirement that owners surrender allowances under the assurance provisions would be triggered only for owners of units in a state where the total state EGU emissions for a control period exceed the applicable state budget with the variability limit. Moreover, only an owner whose units" emissions exceed the owner's share of the state budget with the variability limit would be subject to the allowance surrender requirement.

In applying the additional criteria, EPA would evaluate which source owners in the state had emissions exceeding the respective owner's share of the state budget with the variability limit (regardless of whether the source had enough allowances to cover its emissions). An owner's share would equal the sum of the allocations of its EGUs in the state, plus its proportional share of the amount of the variability limit that, when included with the state budget, was exceeded by the state's EGU emissions during the year involved. If the state emissions exceeded both the state budget with the 1-year and with the 3-year variability limit, then the 3-year variability limit would be used in determining the owner's share of the state budget.

On the other hand, if the state's total EGU emissions for a control period in a given year did not exceed the state budget with the state's 1-year variability limit and did not exceed, on a 3-year rolling average basis, the state budget with the state's 3-year variability limit, then the additional criteria concerning the emissions of each owner's sources in the state would not apply. For more details see subsection V.D.4.i, later, and the rule text at the end of this preamble (§§ 97.425, 97.525, 97.625, and 97.725—Compliance with assurance provisions).

As discussed previously, EPA would not allocate emissions allowances to a new unit for the control period during which the unit commences commercial operation. In the case where assurance provisions for a state are triggered in the year that a new unit first operates, the owner's share—if calculated as the sum of the allocations of its EGUs plus its proportional share of the variability limit—would necessarily be zero because the new unit would have no allocation for that year. Instead, EPA would use a specific surrogate emissions number to calculate the maximum amount the unit could emit in that year before being required to surrender allowances under the assurance provisions. The surrogate emissions number would apply only if the state's assurance provisions were triggered and only in the first year of the new unit's operation.

The surrogate emissions number would be calculated by multiplying the unit's allowable emissions rate (in lbs/MWe) by the unit's maximum hourly load (in MWe/hr) and a default capacity factor specific to the unit type. The default capacity factors would be: 84 percent for coal-fired units, 66 percent for gas-fired combined cycle units, and 15 percent for combustion turbines in the NO_X annual and SO_2 trading programs; and 89 percent for coal-fired units, 72 percent for gas-fired combined cycle units, and 22 percent for combustion turbines in the NO_X ozone season trading program. These percentages are based on the 95th percentile capacity factors for these unit types in quarterly data that have been reported to EPA for coal-fired units commencing operation since 2000 and combustion turbines since 2004. EPA believes that this approach would cover a range of operating conditions for new units and thus avoid attributing to each new unit a share of the state budget with variability reflecting the maximum amount of emissions possible for the unit in its first operating year, in the case where the state's assurance provisions were triggered. (See "Capacity Factors Analysis for New Units" TSD in the docket for further information on the proposed default capacity factors for new units).

These assurance provisions are above and beyond the fundamental requirement for each source to hold enough allowances to cover its emissions in the control period. Failure to hold enough allowances to cover emissions is a violation of the CAA, subject to an automatic penalty and discretionary civil penalties, as described later.

EPA believes the likelihood of triggering assurance provisions is low. The State Budgets/Limited Trading programs have a regional cap that limits overall emissions; state-specific budgets that are the basis for allocating emissions allowances in each state; assurance provisions that each state eliminates the excess emissions leading to significant contribution and interference with maintenance that EPA has identified in this proposed action; and additional allowance surrender requirements for not meeting emissions reductions requirements. As discussed in section e, later, the underlying mechanism of cap and trade, even without assurance provisions, has succeeded in reducing emissions below allowance levels. The accumulated data, history, and experience from these programs underscore that emissions reductions requirements and environmental and public health goals of the programs were met. However, unlike earlier cap and trade programs (*e.g.*, the Acid Rain, CAIR, and NO_X Budget Trading Programs), where allocations were made based on the same average emissions rates for classes of units, in this proposed rule EPA specifically designed budgets that were intended to match up with reductions at certain cost levels used to determine the respective state's significant contribution and interference with maintenance. This means more units are likely to have allocations close to their emissions when the state is eliminating its significant contribution and interference with maintenance and there is likely to be less need for trading in order for sources to comply with the requirement to hold allowances covering emissions. Additionally, EPA has now added assurance provisions to ensure that emissions within a state do not exceed the state budget with the variability limitation.

The existence of these assurance provisions will limit incentives to trade and ensure that state emissions will stay below the level of the budget with the variability limit. An example of a circumstance that might result in emissions approaching the variability limit is an extended nuclear unit outage that causes a company to run its fossil units harder to meet demand. Increased emissions under such a scenario would not result from the ability to trade across state boundaries, or because the fossil units were not controlled, but because the units were operated more. In this type of scenario, emissions would also be higher in a rate-based program that did not allow interstate trading.

EPA is setting two criteria to determine if a state has exceeded its budget using the state budget with the 1-year variability limit on an annual basis, and the state budget with the 3-year variability limit on a 3-year rolling average basis. EPA proposes that emissions from an owner's EGUs in excess of the owner's share of the state budget with the variability limit would not be a violation of the regulation or the CAA. But the owner would be required to make an allowance surrender of one allowance for each ton emitted over the owner's proportional share of the amount by which state emissions exceed the state budget with the variability limit.

This allowance surrender requirement is significant, and EPA believes sufficient, to ensure that the state emissions will not exceed the budgets plus the variability limit. The allowance surrender requirement, however, is less severe than the penalties (discussed later) that apply if a source fails to comply with the requirement to hold an allowance for each ton emitted by EGUs at the source. However, failing to hold sufficient allowances to meet the allowance surrender requirement would be a violation of the regulations and the CAA.

EPA requests comment on whether the allowance surrender requirement should be different (either more or less) than one allowance per ton emitted over the owner's proportional share of the state budget with the variability limit. In addition, EPA requests comment on whether the exceedance of total emissions by an owner's sources over the owner's share of the state budget with the variability limit should be a violation of the CAA and thus subject to discretionary penalties. Finally, EPA requests comment on all aspects of the proposed assurance provisions in the proposed FIPs.

(6) Penalties

All covered sources must hold an allowance for each ton of SO_2 or NO_X emitted and are subject to penalties if they fail to comply with this allowance-holding requirement.

Each source must hold in its compliance account in the AMS enough allowances issued for the respective annual trading program (SO_2 group 1, SO_2 group 2, or NO_X annual programs) to cover the annual emissions of the relevant pollutant from all the EGUs at the source. The source owner must provide, for deduction by the Administrator, one allowance as an offset and one allowance as an excess emissions penalty for each ton of excess emissions. These are automatic penalties-they are required, without any further action by EPA (*e.g.*, any additional proceedings), regardless of the reason for the occurrence of the excess emissions. In addition, each ton of excess emissions, as well as each day in the averaging period (*i.e.*, a calendar year), is a violation of the CAA, for which the maximum discretionary penalty is $25,000 (inflation-adjusted to $37,500 for 2009) per violation under CAA Section 113.

For the ozone season control program, the same provisions apply as for an annual program, except that the control period (and averaging period) is the ozone season, not a calendar year. Consequently, the relevant allowances and emissions are for an ozone season.

EPA requests comment on the amount of allowances required for the automatic penalties.

c. 2012 and 2013 Transition Period

For the 2012–2013 transition period, EPA is proposing the State Budgets/Limited Trading remedy without the previously-described assurance provisions (penalty provisions would remain in effect), but taking comment on whether the assurance provisions should be in force during that period.

New state-specific control budgets (developed as described in section IV) and new allowances would be allocated to sources in the Transport Rule region. These state budgets would reflect the operation of all existing and planned emission control devices. Under EPA's proposed approach, for 2012 and 2013, intrastate and interstate trading, without the assurance provisions, would be allowed.

The locations of existing and planned air pollution control retrofits on EGUs are known, and this knowledge provides greater certainty of where reductions will occur and how these reductions should impact air quality in downwind areas. There would not be sufficient time to complete construction of additional control retrofits or entirely new, controlled EGUs before 2014.[87]

Consequently, EPA believes that there is a high level of certainty that emissions reductions projected for

[87] U.S. Environmental Protection Agency (U.S. EPA). 2002. Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies. Washington, DC.

2012–2013 with interstate trading would be achieved within the states where they are projected to occur, making imposition of the assurance provisions during 2012–2013 unnecessary. In addition, EPA believes that the two alternative options discussed later present greater implementation challenges than this proposed interim remedy for 2012–2013. See sections V.D.5 and V.D.6. Except for the absence of the assurance provisions, the remedy for 2012–2013 would be the same as the State Budgets/Limited Trading option, including compliance and penalty provisions described previously.

The 2012–2013 transition period would provide time for sources to migrate to the new rule requirements in 2014, such as preparing for the imposition of the assurance provisions and, for some states, tighter SO_2 budgets. EPA is requesting comment on the proposed approach of locking in emissions reductions for 2012 and 2013 by allocating new state-specific budgets based on significant contribution and interference with maintenance and ensuring that pollution control devices operate, while allowing for interstate trading in 2012 and 2013 without the assurance provisions. Assurance provisions would provide sources less flexibility and therefore likely increase compliance costs, but would be required starting in 2014. EPA requests comment on the pros and cons of including assurance provisions or other limitations on trading during the 2012–2013 period. Section IV.F presents variability limits for the alternative where assurance provisions would apply during 2012 and 2013 (see Tables IV.F–1 through IV.F–4).

d. Electric Reliability

The State Budgets/Limited Trading remedy is not a risk to electric reliability. The option for sources to trade across state borders and to emit up to the specified state budget with variability limit gives ISOs (Independent System Operators) the flexibility to manage regional electricity generation so that reliability is maintained. For example, the operations of the electricity generation sector under the State Budgets/Limited Trading remedy, as compared to the option allowing only intrastate trading, would be less constrained by state borders and have greater flexibility to handle unexpected events such as extreme weather or the loss of generating capacity for extended periods of time.

e. How Emissions Cap and Trade Programs Have Worked Under Title IV, the NO_X SIP Call, and CAIR

Even absent assurance provisions, cap and trade programs have resulted in broad-based emissions reductions distributed across the entire covered area, with the reductions coming where emissions were highest and most cost effective. The national SO_2 emissions cap and trade program that EPA implemented under Title IV of the CAA Amendments (the Acid Rain Program) and the regional SO_2 and NO_X programs established under CAA section 110(a)(2)(D)(i), in the form of the NO_X Budget Trading Program and the three CAIR trading programs, all have several key components in common:

• Phases and reductions.
◦ An emissions cap is established and the programs are phased in, with increasing stringency to lower emissions.
• Allowance allocation.
◦ Authorizations to emit, *i.e.*, allowances, are allocated to affected sources and are limited by each state's trading budget.
• Allowance trading.
◦ Markets enable sources to trade allowances.
• Flexible compliance.
◦ Sources have the flexibility to choose the most efficient way to comply including adding emission control technologies, updating control technologies, optimizing existing controls, switching fuels, and buying allowances.
• Annual reconciliation.
◦ At the end of every compliance period, each source must surrender sufficient allowances to cover its emissions. Excess allowances may be sold or banked for future use.
• Penalties and enforcement.
◦ There are automatic penalties and potentially discretionary civil penalties for program noncompliance.
• Stringent monitoring and reporting.
◦ Sources must use approved monitoring methods under EPA's stringent monitoring requirements (40 CFR part 75) to monitor and report emissions.
• Data transparency.
◦ The data on key program elements, such as emissions, allocations, and allowance trades, are publicly available on EPA's web site and in annual progress reports.

About 50 government staff operate these cap and trade programs. They have been successful in achieving the emissions reductions goals at reasonable costs with virtually 100 percent program compliance. In the following paragraphs, specific results from the programs are described. These results are documented in program progress reports that are available on EPA's Web site (*http://www.epagov/airmarkets/progress/progress-reports.html*) and in the docket to this rule, as referenced at the end of each program section later.

Title IV Acid Rain Program—Emissions Reductions

Since program implementation in 1995, the ARP has reduced SO_2 and NO_X emissions from the power sector across the nation. In 2008, the ARP SO_2 program covered 3,572 electric generating units (including 1,055 coal-fired units, which account for almost 99 percent of total ARP unit SO_2 emissions). Verified data submitted to EPA from 2008 show that:

• SO_2 emissions from power sector sources were 7.6 million tons, which is 52 percent less than 1990 levels and already below the statutory annual emission cap of 8.95 million tons set for compliance in 2010.
• NO_X emissions from power sector sources were 3.0 million tons, which is 51 percent less than 1995 levels and more than double the Title IV NO_X program emission reduction objective, but also reflects reductions achieved under the NO_X Budget and CAIR NO_X trading programs.

The largest reductions have occurred in the states with the highest power plant emissions. These high emitting areas were upwind of major populations centers and areas of environmental and ecological concern. Emissions reductions have led to improvements in air quality with significant benefits to sensitive ecosystems and human health.

• Between the 1989 to 1991 and 2006 to 2008 observation periods, decreases in wet sulfate deposition averaged more than 30 percent for the eastern U.S.
• Acid Neutralizing Capacity (ANC), the ability of water bodies to neutralize acid deposition, increased significantly from 1990 to 2008 in lake and stream long-term monitoring sites in New England, the Adirondacks, and the Northern Appalachian Plateau.
• Recently updated assessments of U.S. $PM_{2.5}$ and ozone health-related benefits estimate that $PM_{2.5}$ benefits due to ARP implementation in 2010 are valued at \$170–\$410 billion annually and ground-level ozone benefits from ARP implementation in 2010 are valued at \$4.1–\$17 billion (estimates are in 2008 dollars). The benefits are primarily from reduced premature mortality.

See EPA's docket for this rule and *http://www.epagov/airmarkets/progress/ARP_4.html.*

NO_X SIP Call NO_X Budget Trading Program—Emissions Reductions. From 2003–2008, the NBP reduced ozone season NO_X emissions throughout the NO_X SIP Call region each year. Results of the program include:

• In 2008, NBP ozone season NO_X emissions totaled 481,420 tons, which is 62 percent below 2000 levels and 9 percent below the 2008 NO_X emissions cap. Emissions were also below the caps in 2006 and 2007.

• The average NO_X emissions rate for the 10 highest electric demand days (as measured by megawatt hours of generation) consistently fell every year of the NBP.

• The largest NO_X emissions reductions and 8-hour ozone concentrations reductions took place along the Ohio River Valley, as was projected by EPA air quality models of the NO_X SIP Call.

• Noticeable improvements in ambient concentrations of ozone have been measured across the region.

• Of the 104 areas in the eastern United States designated to be in nonattainment for the 1997 8-hour ozone NAAQS in 2004, 88 areas (85 percent) had ozone air quality better than the level of the 1997 standard in 2008. 8-hour ozone concentrations were 10 percent lower in 2008 than in 2001. This decline is largely due to reductions in NO_X emissions required by the NO_X SIP Call rule.[88]

Over the past several years a series of studies [89] [90] [91] have evaluated the NO_X SIP Call and the link between decreasing NO_X emissions and decreasing ozone concentrations. These studies demonstrate that the NO_X SIP Call has been effective in improving ozone air quality in the eastern U.S.

EPA stopped administering the NBP at the conclusion of 2008 control period. States still have the emissions reductions requirements under the NO_X SIP Call and can use the CAIR NO_X ozone season trading program to meet these.

See EPA's docket for this rule for more details on the results of the NO_X Budget Trading Program, or see *http://www.epagov/airmarkets/progress/NBP_4.html.*

CAIR—Emissions Reductions. Anticipation of the CAIR regional program in 2008 resulted in an additional 2.8 million tons of SO_2 reductions from 2005 levels in the eastern United States, bringing emissions well under the 2010 Title IV cap. The NO_X annual and ozone season programs began on January 1 and May 1, 2009, respectively. The SO_2 program began on January 1, 2010. The CAIR cap and trade programs remain in effect, consistent with the Court's remand, in order to benefit public health and the environment, until EPA replaces the rule.

Allowance trading. Because of the ease with which allowances can be banked, bought and sold, and transferred in the trading programs, robust allowance trading markets have developed over the past fifteen years, along with considerable banking of allowances.

Allowance prices and trading activity under the trading programs were reduced in 2008 in response to the Court's July 2008 decision in North Carolina v. EPA granting petitions for review of CAIR. However, the allowance markets remained active. For a recent assessment on allowance markets, *see http://www.epagov/airmarkets/resource/docs/marketassessmnt.pdf.*

Transaction Costs. The cap and trade program results described previously are real, measurable, and very significant. These results demonstrate that cap and trade is a policy tool that can achieve cost-effective, broad reductions quickly to improve human health and the environment and help states meet their obligations to attain the NAAQS. While some have suggested that transaction costs associated with cap and trade programs were high or problematic, EPA has found no indication that this is the case. Transaction costs are important because they can diminish the incentive to trade or the amount traded.

In fact, few empirical studies on transaction costs have been done. EPA has searched the literature and compiled a list of anecdotal discussions on transaction costs, including a study of the ARP's SO_2 cap and trade program by Ellerman [92] of MIT, published in 2004. Ellerman suggests that, while no comprehensive study has been conducted on the subject, "* * * the creation of a standard unit of account in allowances and the lack of any review requirement for trading has avoided the very large transactions costs that limited * * * earlier experiments with emissions trading." Other studies (see Schennach, 2000 [93]) suggest transaction costs are about one percent of the allowance price. An industry expert, Gary Hart,[94] suggested that a typical fee charged by a brokerage firm is $0.50 for each SO_2 allowance.

Tietenberg, in his book, *Emissions Trading Principles and Practice,*[95] explains the role of transaction costs and their impact on trading. Note that Tietenberg and many economists use the word, "permits," in the same way EPA uses the word, "allowances."

Tietenberg defines transactions costs as "the costs, other than price, incurred in the process of exchanging goods and services. These include the costs of researching the market, finding buyers or sellers, negotiating and enforcing contracts for permit transfers, completing all the regulatory paperwork, and making and collecting payments." [96] He also describes how to lower transaction costs, as follows: "Transaction costs can be lowered by making permit transactions transparent, by the availability of exchanges and knowledgeable brokers, and by the sharing of information on the availability of cost-effective abatement technologies, while administrative costs can be lowered by continuous emissions monitoring and by software that streamlines monitoring and reporting." [97] He goes on to say, "Price transparency (making prices public) can reduce the uncertainty associated with trading and facilitate negotiations about price and quantity. One good example is [the] public auctions held each spring for the Sulfur Allowance Program [ARP]." [98]

Tietenberg contrasts EPA's earlier credit-based trading programs in the

[88] U.S. EPA, Our Nation's Air Status and Trends through 2008, Office of Air Quality Planning and Standards, EPA–454/R–09–002, Research Triangle Park, NC, pp. 1, 17.

[89] Gégo, E., P.S. Porter, A. Gilliland, and S.T. Rao, 2007: Observation-Based Assessment of the Impact of Nitrogen Oxides Emissions Reductions on Ozone Air Quality over the Eastern United States. J. Appl. Meteor. Climatol., 46, 994–1008.

[90] Godowitch, J.M., Hogfrefe, C., & Rao, S.T. 2008. Diagnostic analyses of a regional air quality model: Changes in modeled processes affecting ozone and chemical-transport indicators from NO_X point source emission reductions. Journal of Geophysical Research, 113, D19303, doi:10.1029/2007JD009537.

[91] Godowitch, J.M., Gilliland, A.B., Draxler, R.R., and Rao, S.T. 2008. Modeling assessment of point source NO_X emission reductions on ozone air quality in the eastern United States. Atmospheric Environment, 42 (1), 87–100.

[92] Ellerman, A. Denny. 2004. "The U.S. SO_2 Cap-and-Trade Programme," Tradeable Permits: Policy Evaluation, Design and Reform, chapter 3, pp. 71–97, OECD.

[93] Schennach, S.M. 2000. The Economics of Pollution Permit Banking in the Context of Title IV of the 1990 Clean Air Act Amendments. Journal of Environmental Economics and Management 40(3): 189–210.

[94] Personal communication with Gary Hart, ICAP-United, June 25, 2007 as quoted in Napolitano, S., J. Schreifels, G. Stevens, M. Witt, M. LaCount, R. Forte, & K. Smith. 2007. "The U.S. Acid Rain Program: Key Insights from the Design, Operation, and Assessment of a Cap-and-Trade Program." Electricity Journal. Aug/Sept. 2007, Vol. 20, Issue 7. doi:10.1016/j.tej.2007.07.001.

[95] Tietenberg, T.H. 2006. Emissions Trading Principles and Practice. Washington, DC. Published by Resources for the Future.

[96] *Ibid.,* p. 41.

[97] *Ibid.,* p. 73.

[98] *Ibid.,* pp. 70–71.

1970s and 1980s (U.S. Emissions Trading Program (ETP)) with cap and trade programs, such as the Acid Rain Program for SO_2. He says that while credit-based programs "typically involved a considerable amount of regulatory oversight at each step of the process (*e.g.*, certification of credits and approval of each trade)," cap and trade programs use instead a system "that compares actual and authorized emissions at the end of the year, which can lower transactions costs" compared to a credit program.

All the features Tietenberg highlights comprise fundamental aspects of EPA's cap and trade program design. Program design remains one of the principle ways to ensure lower transaction costs. Over the last 15 years, EPA's state-of-the-art information management system has evolved in parallel with the advancement of technology in order to offer platforms for reporting and receiving data and for public access. EPA provides dedicated assistance for sources, states, and regions around the country on program operations and monitoring and reporting, specifically. With limited oversight of transactions, EPA focuses on recording data and information accurately, including allowance transfers, as well as "true-up", where actual emissions are reconciled with allowances held in accounts for compliance.

These features of EPA's program management lead to low transaction costs. EPA is attuned to trying to keep requirements as simple and straightforward as possible, and offers substantial and routine training to ensure successful program implementation and regulatory compliance. While some have equated the length of EPA's trading program rules with higher transaction costs, in fact, the detailed regulatory sections, such as for allocations and the stringent monitoring requirements, form the basis of what actually allows the programs to function with limited oversight, virtually 100 percent compliance, public transparency, and nominal transaction costs.

For the ARP, NO_X Budget Trading Program, and CAIR trading programs, EPA records all allowance allocations in accounts in an electronic allowance tracking system (currently called the AMS). In addition, EPA records in the AMS all allowance transfers that are submitted by parties for official recordation. These allowance accounts are searchable and visible to the public. The trading program regulations that directly govern allowance trading, *i.e.*, the regulations governing the establishment of allowance accounts and the submission of allowance transfers, are relatively simple and establish requirements that are easy to meet. *See, e.g.*, 40 CFR 96.151(a) (requiring establishment of source compliance accounts). Allowances may be held in an allowance account (*i.e.*, banked) for use or trading in any future year in which the trading program involved is in effect. *See, e.g.*, 40 CFR 96.155 (allowing banking). Further, allowances may be transferred from one account to another with no restrictions except the requirements that the authorized account representative of the transferor account submit to EPA a simple (generally electronic) allowance transfer form identifying the allowances to be transferred and the account to receive them, and that the allowances must be currently recorded in the transferor account. *See, e.g.*, 40 CFR 96.160 (requiring submission of specified allowance transfer form) and 96.161(a)(2) (requiring that allowance be in transferor account). This transparency of data and availability of information allows the allowance market to function smoothly.

EPA research found no indications that transaction costs have been a problem. From discussions with a leading industry consultant we learned that there is enough competition among the approximately fifteen brokerage houses that any attempt at charging fees in excess of market standards will be bid down through competition.[99] In many instances, clients can negotiate fees even lower than market averages. Financial exchanges, such as the Chicago Climate Exchange and New York Mercantile Exchange, added SO_2 and NO_X allowances to their list of commodities. Prior to the vacatur of CAIR, transaction costs (broker fee as a percent of allowance price) were estimated at less than 0.2 percent for SO_2, less than 1.8 percent for seasonal NO_X, and less than 0.5 percent for annual NO_X.[100] These transaction costs are low and not expected to affect program outcome.

In summary, EPA believes its cap and trade programs functioned efficiently and did not result in high transaction costs for several reasons. First, in developing the regulations for the trading programs, EPA strove to make the programs as transparent as possible in order to ensure that relevant data were available to the market, to minimize regulatory oversight of trading activity, and to let the market work unhampered. Strong markets exist that have seen upwards of 273 million SO_2 allowances transferred to date. Educational and professional associations that hold regular conferences for members, regulated entities, government agents, and the public have existed to increase transparency of information and exchange ideas on cap and trade programs for more than a decade.

Further, EPA is not aware of any source participating in the trading programs over the past 15 years that expressed concern about the costs of making allowance transfers. For example, EPA has received no comment in the rulemaking proceedings for the trading programs raising concern about the level of transactions costs for allowance transfers under these programs, and no party challenged the allowance transfer provisions on appeal of any of the trading program rules.

In addition, all available information indicates that actual transactions costs are very low. For a list of some articles written by scholars and economists over the past 15 years on transaction costs, see the docket for this rule.

f. How the Remedy in the Proposed FIPs Is Consistent With the Court's Opinions

The proposed remedy discussed in this section effectuates the statutory goal of prohibiting sources within the state from contributing to nonattainment or interfering with maintenance in any other state. *See North Carolina,* 531 F.3d at 908. The proposed FIPs eliminate all or the emissions that EPA has identified as significantly contributing to downwind nonattainment or interference with maintenance in today's proposed action by requiring sources to participate in emissions trading programs that allow intrastate trading and limited interstate trading, and that also include provisions to ensure that no state's emissions exceed that state's budget with variability limit. These assurance provisions, combined with the requirement that all sources hold emissions allowances sufficient to cover their emissions, effectuate the requirement that emissions reductions occur "within the State."

A state's "significant contribution" is the portion of emissions that must be eliminated.[101] State budgets represent EPA's estimate of the remaining emissions after elimination of significant contribution, but in actuality

[99] Memo from ICF International to EPA Clean air Markets Division, September 17, 2008. *Transaction Costs in Allowance Trading Markets.*

[100] *Ibid.*

[101] Note that in cases where EPA has not fully identified the quantity of emissions that represent significant contribution or interference with maintenance, state budgets define the emissions that remain after the part that has been identified is eliminated.

the amount of remaining emissions may vary. As explained in greater detail previously, both the budgets and the assurance provisions recognize the inherent variability in state EGU emissions. EPA recognizes that shifts in generation due to, among other things, changing weather patterns, demand growth, or disruptions in electricity supply from other units can affect the amount of generation needed in a specific state and thus baseline EGU emissions from that state. Because states' baseline emissions are variable, their remaining emissions after all significant contribution is eliminated are also variable. In other words, EGU emissions in a state, whose sources have installed all controls and taken all measures necessary to eliminate its significant contribution, could in fact exceed the state budget without variability. For this reason, the assurance provisions limit a state's emissions to the state's budget with variability limit.

In addition, the requirement that all sources hold emissions allowances (and the fact that the total number of emissions allowances allocated will be equal to the sum of all state budgets without variability) ensures that the use of variability limits both takes into account the inherent variability of baseline EGU emissions in individual states (*i.e.*, the variability of total state EGU emissions before the elimination of significant contribution) and recognizes that this variability is not as great in a larger region.

The variability of emissions across a larger region is not as large as the variability of emissions in a single state for several reasons. Increased EGU emissions in one state in one control period often are offset by reduced EGU emissions in another state within the control region in the same control period. In a larger region that includes multiple states, factors that affect electricity generation, and thus EGU emissions levels, are more likely to vary significantly within the region so that resulting emissions changes in different parts of the region are more likely to offset each other. For example, a broad region can encompass states with differing weather patterns, with the result that increased electricity demand and emissions due to weather in one state may be offset by decreased demand and emissions due to weather in another state. By further example, a broad region can encompass states with differing types of industrial and commercial electricity end-users, with the result that changes in electricity demand and emissions among the states due to the effect of economic changes on industrial and commercial companies may be offsetting. Similarly, because states in a broad region may vary in their degree of dependence on fossil-fuel-based electric generation, the impact of an outage of non-fossil-fuel-based generation (*e.g.*, a nuclear plant) in one state may have a very different impact in that state than on other states in the region. Thus, EPA does not believe it is necessary to allow total regional allowance allocations for the states covered by a given trading program to exceed the sum of all state budgets without variability for these states.

For these reasons, the fact that the proposed use of state budgets with the variability limit may allow limited shifting of emissions between states is not inconsistent with the Court's holding that emissions reductions must occur "within the state." *North Carolina,* 531 F.3d at 907. Under the proposed FIPs, no state may emit more than its budget with variability limit and total emissions cannot exceed the sum of all state budgets without variability. This approach takes into account the inherent variability of the baseline emissions without excusing any state from eliminating its significant contribution. It is thus consistent with the statutory mandate of section 110(a)(2)(D)(i)(I) as interpreted by the Court.

g. Why EPA Is Proposing the State Budgets/Limited Trading Option

The FIPs that EPA is proposing use the State Budgets/Limited Trading remedy to eliminate all of the significant contribution and interference with maintenance that EPA has identified. This remedy—which would use state budgets (*see* section IV) and allow full trading within each state and limited trading outside of each state—would be a cost-effective method for eliminating all or part of each state's emissions that constitute a significant contribution and interfere with maintenance, would be consistent with the Court's decision in *North Carolina* v. *EPA,* and would address the issues raised by the Court.

In the first phase (2012 and 2013), the proposed remedy would provide a new interstate trading program that would ensure existing and planned pollution controls operate. Units would be required to run their existing, or already planned, pollution control devices when the units are operating. The State Budgets/Limited Trading remedy would use the new state budgets described in section IV and allocate allowances to individual sources using a methodology directly related to the methodology used to identify emissions that significantly contribute to nonattainment or interfere with maintenance in downwind areas. EPA believes that because the location of existing and already planned pollution controls for 2012 and 2013 is known, the use of these budgets, even without the added assurance provisions, would assure that the necessary emissions reductions would occur in each state under the trading programs during those years. The impact of the resulting emissions reductions on atmospheric concentrations of particulate matter and other pollution, and subsequent benefits for the environment and human health, would be significant and are described in sections III.B and IX. The proposed remedy would offer the most expeditious approach practicable for compliance in 2012–2013, given the short time available for sources, states, and EPA to implement a transition from CAIR. While there is some uncertainty about how quickly units potentially capable of switching fuels would actually be able to implement such fuel switching, the banking provisions of the State Budgets/Limited Trading approach would provide incentives to reduce emissions as quickly and early as possible. The trading provisions would provide flexibility for sources to purchase allowances in the meantime, without the risks of unexpected high costs, non-compliance, or the inability to operate if unable to switch fuels. The remedy would be relatively easy for sources and states to understand and follow as they transition from prior trading programs to a new regime, beginning in 2014, that would include limits on interstate trading.

The second phase would begin in 2014 with tighter state-specific SO_2 caps for states in the more stringent group 1 tier to address significant contribution and interference with maintenance. In addition, assurance provisions limiting interstate trading would become effective in each state. This approach in the proposed remedy, which is modeled in several ways after the approaches of the ARP and NBP programs, is likely to lead to virtually 100 percent compliance. The approach ensures that, as we see economic growth, future air quality is not compromised and states can depend on emissions reductions in meeting local air quality goals.

The limited interstate trading permitted in this proposed remedy would address some of the problematic issues identified in the alternative options discussed later, such as, under the intrastate trading option, concerns about the administrative burden and needed resources associated with administering 82 new trading programs (with 82 new sets of allowances), conducting 82 annual auctions, concentrated allowance market power within individual states, and regional electricity reliability. In particular, the interstate trading component with assurance provisions would mean that allowances issued for one state for a trading program could be used in any of the states included in the respective trading program. This feature of the proposed remedy would create a regionwide allowance market, rather than single-state allowance markets where individual owners of sources would be much more likely to have market power (see discussion later in section V.D.5). Further, the interstate trading component with assurance provisions would provide source owners with much more flexibility to ensure electric reliability in the event of future variability in electricity demand (*e.g.*, due to weather or economic changes) or in the availability of specific individual electricity generation facilities.

In addition, the proposed State Budgets/Limited Trading remedy provides reductions at a lower cost than the direct control option described later and is flexible enough to accommodate unit-specific circumstances. In contrast, the direct control option described later would involve a complex process of determining unit-by-unit emissions limits that might need to take account of unit-specific circumstances. Moreover, this option would be roughly $600 million (2006$) more expensive than the proposed remedy in 2012. See section V.E for more details on projected costs and emissions.

In summary, EPA believes that interstate trading, although limited by the assurance provisions, would allow source owners to choose among several compliance options to achieve required emissions reductions in the most cost-effective manner, such as installing controls, changing fuels, reducing utilization, buying allowances, or any combination of these actions. Interstate trading with assurance provisions would also allow the electricity sector to continue to operate as an integrated, interstate system able to provide electric reliability. Compared to the alternative options, EPA believes the State Budgets/Limited Trading remedy would provide the greatest flexibility to companies complying with the rules and is the approach most likely to achieve the goals and principles outlined in section III.C.

The proposed remedy provides intrastate and interstate trading components that simplify implementation for EPA (and, where applicable, states) and sources and results in cost-effective achievement of required emissions reductions. Resource needs for EPA and sources to implement the proposed remedy are expected to be comparable to the resources necessary to implement CAIR.

EPA believes the State Budgets/Limited Trading proposed remedy provides more assurance that the emissions levels necessary to address NAAQS nonattainment are not exceeded than most previous regulatory programs such as rate-based direct control programs and even nonattainment plans, none of which places an absolute cap on emissions. EPA has pointed out, in contrast, that the results from cap and trade programs such as the Acid Rain and NO_X Budget Trading programs demonstrate how substantial emissions reductions have been delivered throughout the respective covered region with high levels of compliance, at low costs, and with significant health and ecological benefits. The proposed State Budgets/Limited Trading remedy provides added assurance that emissions reductions now will occur on a state-by-state basis, not just overall at a regional level. These assurance provisions would prohibit states from exceeding their state-level budgets with variability limits and impose stringent and costly allowance surrender requirements that are known upfront to deter exceedances. EPA is confident that the proposed program is both reasonable to implement and stronger than the alternative options.

Additionally, this remedy approach and the method EPA proposes for determining significant contribution together provide a workable regulatory structure for not only dealing with the transport problem for the existing NAAQS, but also would be usable in the years ahead when EPA considers further revisions of the NAAQS, notably for ozone and fine particles. EPA requests comment on the State Budgets/Limited Trading proposed remedy. EPA is also requesting comment on the two options described later in sections V.D.5 and V.D.6.

h. Other Limited Interstate Trading Options Evaluated

EPA considered a range of ways to create an interstate-trading-with-limitations option consistent with the direction provided by the Court. One option considered was to put in place simultaneously intrastate trading with direct control requirements and interstate trading with direct control requirements. The challenges associated with developing direct control requirements are discussed in section V.D.6 later.

EPA also considered interstate trading with backstop provisions, which were rejected as not workable. EPA considered a backstop provision that prohibited the units in a state from future participation in the interstate trading program if the state's emissions in a control period in any year exceeded the state's budget with variability. In that event, the units would be limited to intrastate trading only in the control period of the next year. This is not EPA's proposed option because data on annual emissions are not final until several months into the next year, making it hard for the units in a state to know early enough whether they would be in the interstate trading program or an intrastate trading program for that next year. This would make compliance planning and implementation of compliance plans extremely difficult and adversely affect allowance markets.

In summary, EPA rejected these alternatives as more complicated and perhaps problematic to implement. Instead, EPA is proposing the State Budgets/Limited Trading remedy, which is similar in many ways to the approaches implemented in the past that have succeeded in reducing emissions. However, in order to address the Court's concerns about trading, the proposed remedy includes assurance provisions to ensure that the remedy removes each upwind state's significant contribution and interference with maintenance. The "Other Remedy Options Evaluated" TSD in the docket contains greater detail on the deliberations undertaken to evaluate other options for this rulemaking.

i. Structure and Key Elements of Proposed Transport Rule Trading Program Rules for State Budgets/Limited Trading

This preamble section describes the structure and key elements of the proposed Transport Rule trading program rules for the State Budgets/Limited Trading remedy in the proposed FIPs. Proposed regulatory text that would be added to the Code of Federal Regulations if this option is finalized appears at the end of this notice. EPA requests comment on the structure and key elements of the program as well as on the proposed regulatory text.

In order to make the proposed FIP trading program rules as simple and consistent as possible, EPA designed them so that the proposed rules for each of the trading programs (*i.e.*, the Transport Rule NO_X Annual trading program, Transport Rule NO_X Ozone Season trading program, Transport Rule

SO_2 Group 1 trading program, and Transport Rule SO_2 Group 2 trading program) would be parallel in structure and contain the same basic elements. For example, the proposed rules for the Transport Rule NO_X Annual, NO_X Ozone Season, SO_2 Group 1, and SO_2 Group 2 trading programs would be located, respectively, in subparts AAAAA, BBBBB, CCCCC, and DDDDD of Part 97. Moreover, the order of the specific provisions for each trading program would be same, and the provisions would have parallel numbering. The key elements of the proposed Transport Rule trading program rules are discussed later.

(1) General Provisions

(i) §§ 97.402 and 97.403, 97.502 and 97.503, 97.602 and 97.603, and 97.702 and 97.703—Definitions and Abbreviations

The definitions and measurements, abbreviations, and acronyms would be the same in all four proposed Transport Rule trading programs, except where necessary to reflect the different pollutants (NO_X and SO_2), control periods (for NO_X, annual and ozone season), and geographic coverage (for SO_2, Group 1 and Group 2) involved. Moreover, many of the definitions would be essentially the same as those used in prior EPA-administered trading programs, in some cases with modifications to reflect the specific, proposed Transport Rule trading program involved. For example, the definitions of "unit" and "source" would be the same as in prior trading programs. As a further example, the definitions of "allowance transfer deadline," "owner," and "operator" would be the same as in prior trading programs, except for references to Transport Rule NO_X Annual allowances, Transport Rule NO_X Ozone Season allowances, Transport Rule SO_2 Group 1 allowances, or Transport Rule SO_2 Group 2 allowances or Transport Rule NO_X Annual units and sources, Transport Rule NO_X Ozone Season units and sources, Transport Rule SO_2 Group 1 units and sources, or Transport Rule SO_2 Group 2 units and sources, as appropriate. As a further example, the term "Allowance Management System" would be used instead of the term "Allowance Tracking System" but would have essentially the same definition, while referencing the type of allowances appropriate for the proposed Transport Rule trading program involved. As a further example, "continuous emission monitoring system" is essentially the same as in prior trading programs, except for references to the proposed Transport Rule trading program rules.

Some definitions would be similar to those used in prior EPA-administered trading programs but with some substantive differences. For example, the definitions of "cogeneration unit" and "fossil-fuel-fired," used in the applicability provisions and discussed in this section of the preamble, would be similar to those in prior trading programs but with changes to minimize the need for data concerning individual units or combustion devices for periods before 1990.

A few new definitions would be included to reflect unique provisions of the proposed Transport Rule trading programs. For example, the terms, "owner's assurance level" and "owner's share", would be used in the Transport Rule assurance provisions and defined in the proposed Transport Rule trading program rules. The assurance provisions are discussed previously in section V.D.4.b.

(ii) §§ 97.404 and 97.405, 97.504 and 97.505, 97.604 and 97.605, and 97.704 and 97.705—Applicability and Retired Units

The applicability provisions would be the same for each of the proposed Transport Rule trading programs, except that the provisions would reflect (through the definition of "state") differences in the specific states whose EGUs are covered by the respective Transport Rule trading programs (as discussed in section IV.D of this preamble). In general, the proposed Transport Rule trading programs would cover fossil fuel-fired boilers and combustion turbines serving an electrical generator with a nameplate capacity exceeding 25 MWe and producing power for sale, with the exception of certain cogeneration units and solid waste incineration units. The applicability provisions are discussed previously in section V.D.4.b.

The provisions exempting permanently retired units from most of the requirements of the Transport Rule trading programs would be the same for each of the trading programs. The purpose of the retired units" exemption would be to avoid requiring units that are permanently retired to continue to operate and maintain emission monitoring systems, to report quarterly emissions, and to hold allowances, as of the allowance transfer deadline, sufficient to cover their emissions determined in accordance with the monitoring and reporting requirements. Consequently, the retired unit provisions would exempt these units from the rule sections imposing the relevant monitoring, recordkeeping, and reporting requirements and allowance-holding requirements. However, an owner would include each of these permanently retired units that it owns in determining whether and, if so, how many allowances the owner would be required to surrender in compliance with the assurance provisions. As discussed earlier in this section, while these units would have zero emissions once they are permanently retired, the units could continue to receive allowance allocations for several years thereafter. Consequently, an owner would include these units in determining whether the owner's share of total emissions of covered units in a state exceeded its share (generally based on the allowances allocated to its units) of the state budget with the variability limit and thus whether the owner would have to surrender allowances under the assurance provisions.

The exemption for a retired unit would begin on the day the unit is permanently retired. The unit's designated representative (*i.e.*, the person authorized by the owners and operators to make submissions and handle other matters) would be required to submit notification to the Administrator within 30 days of the unit's permanent retirement.

The retired unit exemption provisions would not directly address any permit-related matters concerning these units. This would be consistent with the general approach under the Transport Rule trading program rules of leaving permitting matters largely to be addressed by the existing, applicable state and federal title V permit programs. Permitting is discussed in section VIII of this preamble.

(iii) §§ 97.406, 97.506, 97.606, and 97.706—Standard Requirements

The basic requirements applicable to owners and operators of units and sources covered by the proposed Transport Rule trading programs and presented as standard requirements would include: Designated representative requirements; emissions monitoring, reporting, and recordkeeping requirements; emissions requirements comprising emissions limitations and assurance provisions; permit requirements; additional recordkeeping and reporting requirements; liability provisions; and provisions describing the effect of the Transport Rule trading program requirements on other Act provisions. The paragraphs, in the standard requirements section, that would address designated representative requirements and emissions monitoring, reporting, and recordkeeping requirements would reference the details of these requirements in other sections of the proposed Transport Rule trading program rules.

The paragraphs addressing emissions requirements would describe these requirements in detail and reference other sections that would set forth the procedures for determining compliance with the emissions limitations and assurance provisions. These paragraphs would also explain that: Transport Rule NO_X Annual allowances, Transport Rule NO_X Ozone Season allowances, Transport Rule SO_2 Group 1 allowances, or Transport Rule SO_2 Group 2 allowances would each authorize emission of one ton of emissions under the applicable Transport Rule trading program; such authorizations could be terminated or limited by the Administrator to the extent necessary or appropriate to implement any provision of the CAA; and such allowances would not constitute a property right. The proposed Transport Rule SO_2 trading programs use new SO_2 allowances and not CAA Title IV allowances, thus the provisions allowing the Administrator to terminate or limit the Transport Rule trading program allowances under this rule would not be contrary to the Court's *North Carolina* decision, which addressed the Administrator's authority to terminate or limit Title IV SO_2 allowances through the CAIR.

The remaining paragraphs in the standard requirements section concern permitting, recordkeeping and reporting, liability provisions, and the effect on other CAA provisions. As discussed in section VIII of this preamble, the paragraphs concerning permitting requirements would be limited to stating that no title V permit revisions would be necessary to account for allowance allocation, holding, deduction, or transfer and that the minor permit modification procedures could be used to add or change general descriptions in the title V permits of the monitoring and reporting approach used by the units covered by each title V permit. The paragraphs on recordkeeping and reporting would generally require owners and operators to keep on site for 5 years copies (which could be electronic) of certificates of representation, emissions monitoring information (including quarterly emissions data), and submissions and records demonstrating compliance with the proposed Transport Rule trading programs. The paragraphs on liability would state that each covered source and covered unit would be required to meet the Transport Rule trading program requirements, any provision applicable to a source or designated representative would be applicable to the source and unit owners and operators, and any provision applicable to a unit or designated representative would be applicable to the unit owners and operators. The paragraph on the effect on other CAA provisions would state that the Transport Rule trading programs do not exempt or exclude owners and operators from any other requirements under the CAA, an approved SIP, or a federally enforceable permit.

(iv) §§ 96.407, 97.507, 97.607, and 97.707—Computation of Time

These sections would clarify how to determine the deadlines referenced in the proposed Transport Rule trading program rules. For example, deadlines falling on a weekend or holiday are extended to the next business day. These are the same computation-of-time provisions used in prior EPA-administered trading programs.

(v) §§ 97.408, 97.508, 97.608, 97.708 and Part 78—Administrative Appeal Procedures

Final decisions of the Administrator under the proposed Transport Rule trading program rules would be appealable to EPA's Environmental Appeals Board under the regulations that are set forth in part 78 (40 CFR part 78) and are proposed to be revised to accommodate such appeals. Specifically, the list in § 78.1 of the types of final decisions that could be appealed under Part 78 would be expanded to include specific types of decisions under the proposed Transport Rule trading program rules.

Further, under the approach in the existing part 78, an "interested person" (in addition to the official representative of owners and operators or an allowance account involved in a matter) may petition for an administrative appeal of a final decision of the Administrator. In order to expand the "interested person" definition (which is currently in part 72 of the ARP regulations) and make the definition more readily accessible to readers of part 78, the definition would be removed from § 72.2, added in § 78.2, and expanded in a way that would cover the proposed trading program rules. Provisions concerning public availability of information, and provisions concerning computation of time (revised to be consistent with the requirements for computation of time used by the Environmental Appeals Board in other types of administrative proceedings), would also be moved to § 78.2. In particular, the revised "interested person" definition would include, with regard to a decision appealable under Part 78, any person who—in connection with the Administrator's process of making that decision—submitted comments, testified at a public hearing, submitted objections, or submitted their name to be included by the Administrator in an interested persons list.

In addition, § 78.3 would be revised to allow for petitions for administrative appeal of decisions of the Administrator under the proposed Transport Rule trading programs. Further, § 78.4 would be expanded to state that filings on behalf of owners and operators of a covered source or unit under the proposed Transport Rule trading programs would have to be signed by the designated representative of the source or unit. Filings on behalf of persons with an interest in allowances in an account in the proposed programs would have to be signed by the authorized account representative of the account.

(2) Allowance Allocations

Sections 97.410 through 97.412, 97.510 through 97.512, 97.610 through 97.612, and 97.710 through 97.712 would set forth: Certain information related to allowance allocation and for implementation of the assurance provisions; the timing for allocation of allowances to existing and new units; and the procedures for new unit allocations. In particular, these sections would include tables providing, for each state covered by the particular proposed Transport Rule trading program and for each year, the state trading budget (without the variability limit), new unit set-aside, and one-year and three-year variability limits. With regard to existing units, these sections would also state that existing units would be allocated the allowances set forth in appendix A of the relevant Transport Rule trading program rules. These allocations would be permanent (taking into account the reductions in allocations, for the Transport Rule SO_2 Group 1 trading program, from Phase I to Phase II) with one exception. A unit that does not operate (*i.e.*, has no heat input) for three consecutive years starting in 2012 would continue to receive its Appendix A allocation for those years plus only three more years. Starting in the seventh year, the Administrator would stop recording the allocations for the unit and would instead add to the new unit set-aside the allowances that would otherwise have been recorded for the non-operating unit. Because the proposed unit-by-unit allocations are set forth in the "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD cited previously, the proposed Transport Rule trading program rules do not repeat these allocations in Appendix A to each rule. Instead, each Appendix A is reserved, and EPA proposes to include the unit-by-unit allocations, for each Transport Rule trading program, in Appendix A to the respective final Transport Rule trading program rules.

With regard to new units (as well as units whose allocations are subject to the requirement that the Administrator not record them or that the Administrator deduct the amount of the allocation and units that lost their allocations after not operating and that subsequently began operating again), the owner and operator of such units could request, by a specified deadline each year, an allocation from the new unit set-aside for that year and each year thereafter. The allocation would equal that unit's emissions—as determined in accordance with part 75 (40 CFR part 75)—for the control period (annual or ozone season, depending on the Transport Rule trading program involved) in the preceding year. The Administrator would determine whether the total number of properly requested allowance allocations for all units in a state for a control period would exceed the amount in the new unit set-aside for the state for the control period. If not, the Administrator would allocate consistent with all proper requests. If the total number would exceed the new unit set-aside, the Administrator would allocate to each properly requesting unit its proportionate share of the new unit set-aside. The Administrator would provide notice of these determinations (which would reflect these calculations rather than any exercise of discretion on the part of the Administrator) through issuance of a notice of data availability to which parties could submit objections and a second notice addressing any objections. Any unallocated allowances in the new unit set-aside would be allocated to existing units in proportion to their current allocations.

If a unit that was not really a covered unit or a unit that was not subject to the allowance-holding requirement were allocated allowances, the proposed provisions set forth a process under which the allocation would not be recorded or the amount of the recorded allocation would be deducted, with one exception. The exception would be if the process of determining compliance with the emission limitation for the source that includes the unit were already completed, in which case no action would be taken to account for the erroneous allocation for the control period involved.

(3) Designated Representatives and Alternate Designated Representatives

Sections 97.413 through 97.418, 97.513 through 97.518, 97.613 through 97.618, and 97.713 through 97.718 would establish the procedures for certifying and authorizing the designated representative, and alternate designated representative, of the owners and operators of a source and the units at the source and for changing the designated representative and alternate designated representative. These sections would also describe the designated representative's and alternate designated representative's responsibilities and the process through which he or she could delegate to an agent the authority to make electronic submissions to the Administrator. These provisions would be patterned after the provisions concerning designated representatives and alternates in prior EPA-administered trading programs.

The designated representative would be the individual authorized to represent the owners and operators of each covered source and covered unit at the source in matters pertaining to all Transport Rule trading programs to which the source and units were subject. This approach would ensure that one individual was required to be knowledgeable about the requirements of, and responsible for compliance with, all Transport Rule trading programs. One alternate designated representative could be selected to act on behalf of, and legally bind, the designated representative and thus the owners and operators. Because the actions of the designated representative and alternate would legally bind the owners and operators, the designated representative and alternate would have to submit a certificate of representation certifying that each was selected by an agreement binding on all such owners and operators and was authorized to act on their behalf.

The designated representative and alternate would be authorized upon receipt by the Administrator of the certificate of representation. This document, in a format prescribed by the Administrator, would include: Specified identifying information for the covered source and covered units at the source and for the designated representative and alternate; the name of every owner and operator of the source and units; and certification language and signatures of the designated representative and alternate. All submissions (*e.g.*, monitoring plans, monitoring system certifications, and allowance transfers) for a covered source or covered unit would have to be submitted, signed, and certified by the designated representative or alternate. Further, upon receipt of a complete certificate of representation, the Administrator would establish a compliance account in the Allowance Management System for the source involved.

In order to change the designated representative or alternate, a new certificate of representation would have to be received by the Administrator. A new certificate of representation would also have to be submitted to reflect changes in the owners and operators of the source and units involved. However, new owners and operators would be bound by the existing certificate of representation even in the absence of such a submission.

In addition to the flexibility provided by allowing an alternate to act for the designated representative (*e.g.*, in circumstances where the designated representative might be unavailable), additional flexibility would be provided by allowing the designated representative or alternate to delegate authority to make electronic submissions on his or her behalf. The designated representative or alternate could designate agents to submit electronically certain specified documents. The previously-described requirements for designated representatives and alternates would provide regulated entities with flexibility in assigning responsibilities under the Transport Rule trading programs, while ensuring accountability by owners and operators and simplifying the administration of the proposed Transport Rule trading programs.

(4) Allowance Management System

The Transport Rule trading program rules listed later would establish the procedures and requirements for using and operating the Allowance Management System (which is the electronic data system through which the Administrator would handle allowance allocation, holding, transfer, and deduction), and for determining compliance with the emissions limitations and assurance provisions, in an efficient and transparent manner. The Allowance Management System would also provide the allowance markets with a record of ownership of allowances, dates of allowance transfers, buyer and seller information, and the serial numbers of allowances transferred. Consistent with the approach in prior EPA-administered trading program, allowance price information would not be included in the Allowance Management System. EPA's experience is that private parties (*e.g.*, brokers) are in a better position to obtain and disseminate timely, accurate allowance price information than is EPA. For example, because not all allowance transfers are immediately reported to the Administrator for recordation, the Administrator would not be able to ensure that any reported price information associated with the transfers would reflect current market prices.

(vi) §§ 97.420, 97.520, 97.620, and 97.720—Compliance and General Accounts

The Allowance Management System would contain two types of accounts: compliance accounts, one of which the Administrator would establish for each covered source upon receipt of the certificate of representation for the source; and general accounts, which could be established by any entity upon receipt by the Administrator of an application for a general account. A compliance account would be the account in which any allowances used by the covered source for compliance with the emissions limitations and assurance provisions would have to be held. The designated representative and alternate for the source would also be the authorized account representative and alternate for the compliance account. Using source-level, rather than unit-level accounts, would provide owners and operators more flexibility in managing their allowances for compliance, without jeopardizing the environmental goals of the Transport Rule trading programs, because the source-level approach would avoid situations where a unit would hold insufficient allowances and would be in violation of allowance-holding requirements even though units at the same source had more than enough allowances to meet these requirements for the entire source.

General accounts could be used by any person or group for holding or trading allowances. However, allowances could not be used for compliance with emissions limitations or assurance provisions so long as the allowances were held in, and not properly and timely transferred out of, a general account. To open a general account, a person or group would have to submit an application for a general account, which would be similar in many ways to a certificate of representation. The application would include, in a format prescribed by the Administrator: The name and identifying information of the individual who would be the authorized account representative and of any individual who would be the alternate authorized account representative; an identifying name for the account; the names of all persons with an ownership interest with the respect to allowances held in the account; and certification language and signatures of the authorized account representative and alternate. The authorized account representative and alternate would be authorized upon receipt of the application by the Administrator. The provisions for changing the authorized account representative and alternate, for changing the application to take account of changes in the persons having an ownership interest with respect to allowances, and for delegating authority to make electronic submissions would be analogous to those applicable to comparable matters for designated representatives and alternates.

(vii) §§ 97.421 Through 97.423, 97.521 Through 97.523, 97.621 Through 97.623, and 97.721 Through 97.723—Recordation of Allowance Allocations and Transfers

By September 1, 2011, the Administrator would record allowance allocations for existing units, based on Appendix A to each proposed Transport Rule trading program rule, for 2012 through 2014. By June 1, 2012 and June 1 of each year thereafter, the Administrator would record such allowance allocations for each proposed Transport Rule trading program for the third year after the year of the recordation deadline, *e.g.*, for 2015 in 2012. Recording these allowance allocations about 3 years in advance of the first year for which they could be used for compliance would facilitate compliance planning by owners and operators and promote robust allowance markets, including futures markets for allowances. By September 1 (for the Transport Rule NO_X and SO_2 annual trading programs and June 1, for the Transport Rule NO_X Ozone Season program) of each year starting with 2012, the Administrator would record allowance allocations for that year from the new unit set-aside. Because this would occur before the allowance transfer deadline for each proposed Transport Rule trading program involved, this would still allow for trading and thereby promote robust allowance markets.

The process for transferring allowances from one account to another would be quite simple. A transfer would be submitted providing, in a format prescribed by the Administrator, the account numbers of the accounts involved, the serial numbers of the allowances involved, and the name and signature of the transferring authorized account representative or alternate. If the transfer form containing all the required information were submitted to the Administrator and, when the Administrator attempted to record the transfer, the transferor account included the allowances identified in the form, the Administrator would record the transfer by moving the allowances from the transferor account to the transferee account within 5 business days of the receipt of the transfer form.

(viii) §§ 97.424, 97.524, 97.624, and 97.724—Compliance With Emissions Limitations

Once a control period has ended (*i.e.*, December 31 for the Transport Rule NO_X and SO_2 annual trading programs and September 30 for the NO_X ozone season trading program), covered sources would have a window of opportunity (*i.e.*, until the allowance transfer deadline of midnight on March 1 or December 1 following the control period for the annual and ozone season trading programs respectively) to evaluate their reported emissions and obtain any allowances that they might need to cover their emissions during the control period. Each allowance issued in each proposed Transport Rule trading program would authorize emission of one ton of the pollutant, and so would be usable for compliance, for a control period in the year for which the allowance was allocated or a later year. Consequently, each source would need—as of the allowance transfer deadline—to have in its compliance account, or have a properly submitted transfer that would move into its compliance account, enough allowances usable for compliance to authorize the source's total emissions for the control period. The authorized account representative could identify specific allowances to be deducted, but, in the absence of such identification or in the case of a partial identification, the Administrator would deduct on a first-in, first-out basis.

If a source were to fail to hold sufficient allowances for compliance, then the owners and operators would have to provide, for deduction by the Administrator, 2 allowances allocated for the control period in the next year for every allowance that the owners and operators failed to hold as required to cover emissions. In addition, the owners and operators would be subject to discretionary civil penalties for each violation, with each ton of unauthorized emissions and each day of the control period involved constituting a violation of the Clean Air Act.

EPA believes that it is important to include a requirement for an automatic deduction of allowances. The deduction of one allowance per allowance that the owners and operators failed to hold would offset this failure. The deduction of another allowance per allowance that the owners and operators failed to hold would provide an automatic penalty that could not be avoided, regardless of any explanation provided by the owners and operators for their failure, and would therefore provide a strong incentive for compliance with the allowance-holding requirement by ensuring that non-compliance would be a significantly more expensive option than compliance.

(ix) §§ 97.425, 97.525, 97.625, and 97.725—Compliance With Assurance Provisions

EPA proposes to include assurance provisions in the Transport Rule trading programs in order to ensure that each state would eliminate that part of its significant contribution and interference with maintenance that EPA has identified in today's proposed action (*see* section V.D.4.b previously). As previously discussed, a requirement that owners surrender allowances under the assurance provisions would be triggered only for owners of units in a state where the total state EGU emissions for a control period would exceed the applicable state budget with the variability limit. Moreover, only an owner whose units' emissions would exceed the owner's share of the state budget with the variability limit would be subject to the allowance surrender.

The process of determining, for a given control period, which states would have total EGU emissions sufficient to trigger the allowance surrender requirement, which owners would be subject to the allowance surrender, and whether those owners were in compliance would be implemented in a series of steps. (The dates summarized later apply to the proposed annual programs; the dates for the proposed ozone season program would be earlier.)

First, the Administrator would perform the calculations necessary to determine whether any states had total state EGU emissions for a control period greater than the state budget with the variability limit, applying both the 1-year and the 3-year variability limits discussed earlier. By June 1 (starting in 2015), the Administrator would promulgate a notice of availability of the results of these calculations and provide an opportunity for submission of objections. By August 1, the Administrator would promulgate a second notice of availability of any necessary adjustments to the calculations and the reasons for accepting or rejecting any properly submitted objections.

Second, by August 15, the designated representative of every Transport Rule source in a state identified in the August 1 notice as having control period emissions in excess of the budget with the variability limit would make a submission to the Administrator that would identify: Each person having (as of the last day of the control period) a legal, equitable, leasehold, or contractual reservation or entitlement in the Transport Rule units at the source; and the percentage of each such person's reservation or entitlement.

Third, by September 15, the Administrator would calculate, for each state identified in the August 1 notice and for each owner of covered units in the state, the owner's share of emissions, the owner's share of the state budget with the variability limit, and the amount (if any) that the owner would be required to hold for surrender under the assurance provisions (*i.e.*, the owner's proportionate share of the excess of state emissions over the state budget with the variability limit). The Administrator would promulgate a notice of availability of the results of these calculations, provide an opportunity for submission of objections, and promulgate by November 15 a second notice of availability of any necessary adjustments to the calculations and the reasons for accepting or rejecting any properly submitted objections.

By December 1, each owner identified in the November 15 notice as being required to hold allowances for surrender under the assurance provisions would designate a compliance account of one of its covered units in the state, and the authorized account representative of the compliance account would submit to the Administrator a statement designating the compliance account, as the account in which the required allowances would be held.

As of midnight of December 15, the owner would have to have in its designated compliance account, or have a properly submitted transfer that would move into that compliance account, the amount of allowances (usable for compliance) that the Administrator determined (in the calculations referenced in the November 15 notice) were required to be held by the owner for surrender. The authorized account representative could identify specific allowances to be deducted but, in the absence of such identification or in the case of a partial identification, the Administrator would deduct allowances on a first-in, first-out basis.

The potential effect of subsequent data revisions that would otherwise change the data used in and the results of the Administrator's calculations referenced in the August 1 or November 15 notices discussed previously would be limited. If data used in a notice applying the assurance provisions to a given year were revised as a result of a decision in, or settlement of, litigation (such as an administrative appeal resulting in such decision or settlement or an administrative appeal whose results were in turn appealed in a judicial proceeding resulting in such decision or settlement) initiated within 30 days of the promulgation of the notice involved, then the Administrator would use the revised data for the calculations in the respective notice. Any other data revisions would not be used to revise the calculations. The revised data could be used, if relevant, in the Administrator's calculations in future notices promulgated for a later year. If the revised calculations increased the amount of allowances that an owner was required to hold for surrender, the Administrator would set a new, reasonable deadline for the owner to hold the additional allowances in the owner's designated compliance account. The Administrator believes that this limitation on the effect of data revisions on the calculation of the amount of allowances owners would have to surrender under the assurance provisions is necessary. Because an owner's surrender obligation would be calculated using large amounts of data involving all the covered units in a state (including potentially many units owned by other owners), each owner would face the potential that changes in data outside of the owner's responsibility and control could change—after the December 15 allowance-holding deadline—in a way that would increase his surrender obligation after that deadline and put him in violation of the regulations and the Act. EPA believes that this potential risk would be significant enough that it could make many owners reluctant to consider any compliance options involving even the limited interstate trading allowed under the proposed remedy. The proposal would limit this risk by having the Administrator only take account of data revisions resulting from decisions in, or settlement of, litigation initiated soon after promulgation of the notice involved.

Owners' potential allowance surrender obligations as of the December 15 allowance-holding deadline under the assurance provisions would still be significant even with this limitation on the potential for the surrender obligations to increase after December 15 due to data revisions.

As discussed previously, it would not be a violation of the CAA for total state EGU emissions to exceed the state budget with the variability limit or for an owner to become subject to allowance surrender under the assurance provisions. However, the failure of an owner to hold in the designated compliance account a sufficient amount of allowances to satisfy this allowance surrender would violate the CAA and be subject to discretionary penalties, with each required allowance that was not held and each day of the control period involved constituting a violation. EPA believes that the allowance surrender requirement alone—and certainly when coupled with the potential for large discretionary penalties—would ensure that owners would take actions to avoid having total state EGU emissions exceed the level that would trigger the allowance surrender.

(x) §§ 97.426 Through 97.428, 97.526 Through 97.528, 97.626 Through 97.628, and 97.726 Through 97.728—Miscellaneous Provisions

These sections would allow banking of the allowances issued in the Transport Rule trading programs, *i.e.*, the retention of unused Transport Rule allowances allocated for a given control period for use or trading in a later control period. Banking would allow sources to make emissions reductions beyond required levels and bank the unused allowances for use or trading later. This would encourage development of emissions reductions techniques and technologies and implementation of early reductions, stimulate the allowance markets, and provide flexibility to owners and operators. While this could also potentially cause emissions from sources in some states in some control periods to be greater than the allowances allocated for those control periods, the assurance provisions would limit such emissions in a way that would ensure that the part of each state's significant contribution and interference with maintenance that EPA has identified in today's proposed action would be eliminated.

These sections also would provide that the Administrator could, at his or her discretion and on his or her own motion, correct any type of error that he or she finds in an account in the Allowance Management System. In addition, the Administrator could review any submission under the Transport Rule trading programs, make adjustments to the information in the submission, and deduct or transfer allowances based on such adjusted information.

(5) Emissions Monitoring, Recordkeeping, and Reporting

Sections 97.430 through 97.435, 97.530 through 97.535, 97.630 through 97.635, and 97.730 through 97.735 would establish emissions monitoring, recordkeeping, and reporting requirements for Transport Rule units that would result in clear, consistent, rigorous, and transparent monitoring and reporting of all emissions. Such monitoring and reporting would be the basis for holding sources accountable for their emissions and would be essential to the success of the Transport Rule trading programs. This is because consistent and accurate measurement of emissions would be necessary to ensure that each allowance would actually represent one ton of emissions and that one ton of reported emissions from one source would be equivalent to one ton of reported emissions from another source. This would establish the integrity of each allowance and instill confidence in the underlying market mechanisms that would be central to providing sources with flexibility in achieving compliance. Moreover, given the variation in the type, operation, and fuel mix of sources covered by the proposed Transport Rule trading programs, EPA believes that emissions would need to be monitored continuously in order to ensure the precision, reliability, accuracy, and timeliness of emissions data supporting the trading programs.

In §§ 97.430 through 97.435, 97.530 through 97.535, 97.630 through 97.635, and 97.730 through 97.735, EPA proposes the monitoring, recordkeeping, and reporting requirements for the Transport Rule NO_X annual, NO_X ozone season, SO_2 Group 1, and SO_2 Group 2 trading programs, respectively. These provisions reference the relevant sections of Part 75 (40 CFR part 75), where the specific procedures and requirements for monitoring and reporting NO_X and SO_2 mass emissions are found. The proposed provisions are virtually the same as the monitoring, recordkeeping, and reporting requirements under previous EPA-administered trading programs, *e.g.*, the ARP and NO_X Budget and CAIR trading programs.

Part 75 was originally developed for the ARP and addressed SO_2 mass emissions and NO_X emissions rate. The ARP, as established by Congress in CAA Title IV, requires the use of continuous emission monitoring systems (CEMS) or an alternative monitoring system that is demonstrated to provide information with the same precision, reliability, accuracy, and timeliness as a CEMS. Subsequently, Part 75 was expanded, for purposes of the NO_X Budget Trading Program under the NO_X SIP Call, to address monitoring and reporting of NO_X mass emissions. Under Part 75, a unit has several options for monitoring and reporting, namely the use of: A CEMS; an excepted monitoring methodology (NO_X mass monitoring for certain peaking units and SO_2 mass monitoring for certain oil- and gas-fired units); low mass emissions monitoring for certain, non-coal-fired, low emitting units; or an alternative monitoring system approved by the Administrator through a petition process. In addition, under Part 75, the Administrator can approve petitions for alternatives to Part 75 requirements.

The proposed monitoring and reporting provisions for the Transport Rule trading programs would allow use of these same options and petition procedures and would reference the applicable provisions in Part 75. Existing Transport Rule units would be required to install and certify monitoring systems by the beginning of the relevant Transport Rule trading program. New Transport Rule units have separate deadlines based upon the date of commencement of commercial operation. Recognizing that many of the Transport Rule units are already monitoring NO_X and/or SO_2 under Part 75 through existing trading programs, continued use of previously certified monitoring systems would be allowed when appropriate rather than automatically requiring recertification.

The quality assurance (QA) requirements for the ARP that were mandated by Congress under CAA Title IV are codified in Appendices A and B of Part 75. Part 75 specifies that each CEMS must undergo rigorous initial certification testing and periodic quality assurance testing thereafter, including the use of relative accuracy test audits (RATAs) and daily calibrations. A standard set of data validation rules apply to all of the monitoring methodologies. These stringent requirements result in an accurate accounting of the mass emissions from each unit, and EPA provides prompt feedback if the monitoring system is not operating properly. In addition, when the monitoring system is not operating properly, standard substitute data procedures are applied and result in a conservative estimate of emissions for the period involved. This ensures a level playing field among the regulated units, with consistent accounting for every ton of emissions, and also provides an incentive to properly maintain, and meet the QA requirements for, each monitoring system. The monitoring and reporting provisions in the proposed Transport Rule trading program regulations would contain the same QA requirements and substitute data procedures as in Part 75 and would reference the applicable provisions in Part 75.

Part 75 requires electronic submission, to the Administrator and in a format prescribed by the Administrator, of a quarterly emissions report containing all of the emissions data specified in the recordkeeping provisions of Part 75. EPA has found that centralized, electronic reporting using a consistent format is necessary to ensure consistent review and public posting of the emissions data for covered units, which contribute to the integrity, efficiency, and transparency of trading programs. Further, the inclusion of all emissions data in a single quarterly report for each unit means that, if the same data are needed for multiple trading programs, the unit only needs to report it once in the form of one comprehensive report. The reporting provisions in the proposed Transport Rule trading program regulations would contain the same requirements for submission to the Administrator of electronic, comprehensive quarterly reports as in Part 75. As discussed above, the reporting provisions would also include a process for resubmission of quarterly reports where appropriate.

5. State Budgets/Intrastate Trading Remedy Option

As noted earlier in this preamble, in addition to the remedy option included in the proposed FIPs, EPA is taking comment on two alternative options for eliminating all or part of the emissions in upwind states that significantly contribute to nonattainment or interfere with maintenance in downwind states. The first of these alternative options is the State Budgets/Intrastate Trading option described below. EPA is considering the relative merits of this option and requests comment on whether it should be included in the final FIPs. EPA also identifies below a number of disadvantages that raise concerns for EPA and are explained later in this section. EPA requests comment on these issues and their impacts on and significance for any final rule.

a. Description of Option

The State Budgets/Intrastate Trading option would set state-specific caps for SO_2, NO_X annual, and NO_X ozone season emissions from EGUs and create separate allowance trading programs within each state in the respective regions starting in 2012. The state-specific caps would ensure that all required reductions occur within the state and thus would address the Court's concerns about abating each individual upwind state's unlawful emissions under CAA section 110(a)(2)(D)(i)(I). Similar to other trading programs, the owners and operators of each source would be required to surrender to EPA one allowance for every ton of emissions after the end of every control period. However, a source could only use, for compliance with this requirement, an allowance issued for the state where the source was located. For purposes of obtaining allowances usable in compliance, sources within each state could trade allowances amongst themselves, but not with sources located in other states. Total emissions in each state could not exceed that state's budget and there would be no shifting of emissions to other states thus ensuring that each state's contribution to nonattainment and interference with maintenance with regard to downwind states would be adequately addressed. Banking of allowances for use in a later period would be permitted under this remedy option.

Under this option, EPA would allocate allowances to the covered sources within each state, and sources in the state could use for compliance only allowances issued for the same state. Even a company that operates EGUs in multiple states would not be permitted to use for compliance for one of its sources allowances issued to another of its sources in a different state. In essence, this approach, if implemented, would result in 28 separate trading programs for NO_X annual, 26 trading programs for NO_X ozone season, and 28 trading programs for SO_2 for a total of 82 new trading programs to be administered by EPA. These 82 trading programs would require 82 separate sets of allowances. Companies that own EGUs in more than one state would also be responsible for managing their allowances for each program in each state separately.

Unlike the remedy option in the proposed FIPs or the other alternative remedy option, this option does not include assurance provisions based on the variability limits described in section IV. This option includes a "hard" cap for each state equal to its budget, which provides assurance that reductions will occur in each state and which EPA believes makes additional assurance provisions unnecessary. The State Budgets/Intrastate Trading option does allow banking and the use of banked allowances to provide sources with some degree of operational flexibility in complying with the program. Because this option includes provisions for banking emissions allowances (as does the proposed State Budgets/Limited Trading remedy), limited year-to-year (temporal) emissions variability is allowed. EPA requests comment on this approach to providing for emissions variability. EPA also requests comment on whether assurance provisions based on variability limits should be included in this option.

b. How the Option Would Be Implemented

(1) Applicability

Applicability would be the same for the proposed remedy and for the two alternative options, including this one. Refer to section V.D.4 above for detailed discussion on applicability.

(2) Allocation of Emissions Allowances

While the general approach for calculating allowance allocations would be the same as described above for State Budgets/Limited Trading, EPA would not distribute all of the allowances into the source accounts each period. The distribution of allowances would be modified because of the concentrated nature of numerous state power markets, which would be reflected in the state allowance markets if all allowances were distributed in each state based on factors reflecting generation in that state. The electric power sector tends to be highly concentrated, and, within a state, the majority of generation is often owned by a relatively small number of companies. This assessment of state electricity markets is supported by analysis using the Herfindahl-Hirschman Index, a way to measure the size of firms in relation to the industry and an indicator of the amount of competition among them (see Electric Generation Ownership, Market Concentration and Auction Size Technical Support Document). To address this potential issue concerning the allowance markets in many states, under this option some allowances would be withheld from certain sources in each state that control a large share of fossil-fueled power generation and would be made available for companies with a small share of generation in the state.

The reason for including this provision is that the dominant power generation companies in each state would likely receive a large share of the allocated allowances and as a result might be able to exert control over allowance prices in the state's allowance market. This market power and potential for allowance price manipulation could pose a threat to the transparency and liquidity of allowance markets and put small owners of fossil-fuel fired generation at a disadvantage regarding their compliance costs unless the owners were given sufficient access to allowances other than through direct purchase from the state's dominant companies. Some of these owners of a small share of generation might already face higher control costs, higher transaction costs, and less flexibility regarding compliance options.

Moreover, the use of allowance market power to manipulate prices could have wider impacts on electricity markets as a whole, electricity prices, and electricity reliability both within and across state borders. Therefore, the State Budgets/Intrastate Trading approach needs to address the potential for excessive market power and ensure that allowances would be available to all covered sources at reasonable market prices.

In order to address the potential market power issue, under this option, not all allowances would be allocated using the allocation method described above in section V.D.4. Rather, a small portion of allowances would be withheld from companies with a large share of a state's total fossil-fuel fired electricity generation. These allowances would be made available for purchase by companies with a small share of generation through an annual auction.

EPA is soliciting comments on whether a potential market power problem could arise or reasons why market manipulation would not be a concern under this alternative remedy. EPA is also soliciting comments on whether the approach of using an annual auction to make allowances available to small generators would satisfactorily address this potential issue. This approach is detailed in subsection (3) below.

The approach described for new unit set-asides and allocations to non-operating units above for State Budgets/Limited Trading in section V.D.4 would remain the same for this option.

(3) Auction of Emissions Allowances

The use of an annual allowance auction would ensure that companies with a small market share in a state would have access to additional allowances, if needed, other than through direct purchase from a large owner of generation and would reduce the opportunity for market price manipulation by dominant companies. This means that EPA would hold a total of 82 auctions every year to separately auction SO_2 and NO_X ozone season and NO_X annual allowances in each of the 82 intrastate trading programs. The auction format would be single-round, uniform-price, sealed bid with an initial reserve price of 70 to 80 percent of the modeled allowance price. Reserve prices would be updated at regular intervals to reflect changes in average market prices over time. Any unsold allowances would be returned to the sources from which they were withheld on a proportional basis. Revenues from the auctions would be deposited in the U.S. Treasury, in accordance with 31 U.S.C. 3302.

EPA would use auctions to address market power concerns rather than other options it considered. The Agency considered using a different allowance allocation method that would take into account an owner's share of total generation and distribute proportionally more allowances to owners of a small share of the total generation in each state. This would also ensure that small owners had sufficient allowances without relying on the open markets. However, EPA opted to use an allocation methodology based directly on the approach used to quantify each state's significant contribution to ensure that a direct link exists between allocations and significant contribution to nonattainment or interference with maintenance. EPA also considered direct sales of allowances withheld from dominant sources but believes that auctions would be better suited for determining the appropriate prices for allowances than EPA would be at setting fixed allowance prices for all trading programs in all states. For these reasons, EPA believes the use of auctions would be the best method to address the issue of potential allowance market manipulation.

EPA prefers to use the single-round, uniform-price, sealed bid format because it is simple for all participants to understand, relatively simple to implement and administer, and deters collusion among bidders. In addition, the utility sector already is familiar with this type of format, and EPA has several years of experience running single-round, sealed-bid auctions for Title IV SO_2 allowances. Other formats considered such as multi-round auctions are believed to be more complicated for participants to understand and more complex to administer and do not discourage collusion.

Entities that meet the following criteria would be eligible to participate in the allowance auction: (1) They are required to hold allowances in the state for compliance; and (2) they own no more than 10 percent of the total fossil-fuel fired generation within the state based on EPA's modeled generation for 2014. EPA considered a range from 5 to 20 percent share of ownership for all states and believes that 10 percent ownership is appropriate for determining what constitutes a small market share for this rule. EPA believes that by limiting the auction to entities that own no more than 10 percent of the fossil-fuel fired generation in a state, it would ensure that each auction has enough participants to make auctions viable and competitive and also ensure that the allowances are available only to those companies that may be at a disadvantage in the open markets. Companies with more than a 10 percent share of generation tend to operate several units, have more flexibility, receive a significant share of allowances, and face lower control and transaction costs. EPA is requesting comment on the share of electric generation used as a threshold for determining participation in auctions and also the percentage of allowances available through auctions.

To implement this option, EPA would withhold 2 to 5 percent of the allowances that would be allocated to companies with more than 10 percent of the generation in order to supply allowances for auction each period. This amount is small enough not to have a significant impact on those EGUs from which the allowances are withheld and large enough to provide a sufficient number of allowances for auction. In more highly concentrated states where few companies control much of the generation, a relatively greater number of allowances would be available through the auction to the smaller, potentially disadvantaged companies. Conversely, in states where the electricity sector is less concentrated, there is less threat of market manipulation and greater likelihood of liquid markets. Thus, in these states relatively fewer allowances would be withheld for auction.

Another variation on this alternative option would be to divide companies in each state into three groups, instead of just two. The first group would be the companies that own no more than 10 percent of the total fossil-fuel generation within the state and would be able to participate in EPA's allowance auctions. The second group would be companies that own a medium amount of fossil-fuel fired generation (for example, between 10 to 20 percent of the total). These companies would not be allowed to participate in auctions but also would not have to contribute any allowances to the auctions. Finally, the third group would be those remaining companies that own a large share of fossil-fuel generation (for example, more than 20 percent of the total). A small percentage of the allowances allocated to these companies would be withheld to supply the auctions. EPA is asking for comments on this variation on the alternative option and other ways to address potential market power problems and on this alternative option.

(4) Allowance Management System

The allowance management system for the State Budgets/Intrastate Trading option would be consistent with the allowance management system for the State Budgets/Limited Trading programs described above, and with the data system structure EPA has developed for allowance management under its existing cap and trade programs such as the CAIR and the Acid Rain Program.

(5) Monitoring and Reporting

Monitoring and reporting provisions would require complete, quality-assured monitoring, and timely reporting of emissions to assure accountability and provide public access to data, and would be the same for EPA's proposed remedy and the State Budgets/Intrastate Trading option. Refer to section V.D.4 above for detailed discussion on monitoring and reporting requirements.

(6) Penalties

Under the State Budgets/Intrastate Trading option for an annual control program (*i.e.*, any of the 28 SO_2 or 28 NO_X annual programs), the requirement that each source hold in its compliance account one allowance for each ton of emissions, and the penalties for failure to meet this requirement, would be the same as described previously in the Penalties section for the State Budgets/Limited Trading remedy option. However, because sources in a given state can only use allowances issued for that state, the penalties associated with failure to hold one allowance for each ton of emissions are adequate to ensure that emissions from the state do not exceed the state budget (except for some temporal variability due to banking). For this reason, EPA does not believe that any other penalties or assurance provisions (such as the assurance provisions used in the State Budgets/Limited Trading remedy) are necessary to ensure that each state eliminates the portion of significant contribution and interference with maintenance that EPA has identified in today's action. EPA requests comment on this conclusion.

c. How the State Budgets/Intrastate Trading Remedy is Consistent With the Court's Opinions

The state budgets/intrastate trading remedy, by establishing state-specific caps on annual or ozone-season EGU emissions, directly implements the section 110(a)(2)(D)(i)(I) requirement that emissions from sources that 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 be prohibited. Of the three remedy options considered, this option provides the most certainty regarding total annual or ozone-season emissions from each state. For this reason, it most directly addresses the statutory mandate that the emissions reductions occur "within the State."

To implement this remedy option, EPA would use the state budgets without variability limits, developed in accordance with the procedures described in sections IV.D and IV.E. These budgets represent EPA's projection of each affected state's EGU emissions in an average year (before accounting for the inherent variability in power system operations) after the elimination of all emissions that EPA has identified as significantly contributing to nonattainment or interference with maintenance.

The number of allowances in each state budget would be distributed or made available (through an auction or otherwise) to sources in that state. Only allowances distributed or made available to sources in a particular state could be used by sources in that state to satisfy the requirement to hold one allowance for every ton of emissions. Thus, annual (or ozone season) emissions in the state would be capped at the level of the state budget. The limited variability due to banking of emissions could allow limited temporal shifting of emissions, but would not alter the requirement that reductions occur within the state. This remedy is thus sufficient to ensure that all significant contribution and interference with maintenance identified by EPA in today's action is eliminated.

d. Electric Reliability Issues

EPA requests comments about whether the State Budgets/Intrastate Trading alternative option could have adverse consequences for electric reliability. The grid regions, and the movement of electricity within each grid region, do not correspond with, and are not limited by, state borders. For example, an increase in electricity demand (*e.g.*, due to a hot summer), or a decrease in electricity supply (*e.g.*, due to a major generation capacity outage), in a given state will not necessarily be met, or offset, through increased electricity generation in that same state. Instead, the increased demand or reduced supply may well result in increased generation outside that state. The sources of the increased generation will be determined by availability and economics and will not necessarily be confined to generation sources in that state. In fact, the ability to obtain additional or replacement supply from sources in another part of the state or from another state enhances electric reliability.

Although companies in one state obtain electricity from sources in multiple states, the State Budgets/Intrastate Trading option would establish emissions budgets on a state basis and would not allow sources in one state to use allowances issued to sources in other states. A source could use, in covering emissions for the current year, both allowances allocated for the current year and banked allowances issued by its state for a past year. However, this option would provide sources less trading flexibility than the proposed State Budgets/Limited Trading remedy. The other remedy options allow for emissions variability, which should largely address electric reliability concerns.

EPA requests comment on whether the State Budgets/Intrastate Trading alternative would provide sufficient flexibility for reliable operation of the integrated grid and, if not, whether there would be ways of preventing or reducing adverse effects such as including additional emissions variability provisions in this option or other approaches. EPA requests comment on approaches to provide additional emissions variability, or other approaches to increasing flexibility, in this option that would be consistent with eliminating all or part of the significant contribution and interference with maintenance that EPA has identified.

e. How Smaller Market Trading Programs Have Worked

These examples of small trading programs below are relevant to further understanding of the State Budgets/Intrastate Trading remedy option. While small trading programs can succeed, they can also have serious consequences for allowance and electricity markets. Budgets and caps, allowance availability, and prices all can have a profound impact on generation and energy prices for consumers in addition to any air quality benefits. In addition, states range in size and number of potential program participants making each state's circumstances unique and more challenging for EPA to monitor.

(1) Texas Mass Emissions Cap and Trade (MECT)

EPA has approved a NO_X cap and trade program as part of an ozone attainment SIP for the Houston Galveston Brazoria (HGB) nonattainment area in Texas. The program knows as the Mass Emissions Cap and Trade (MECT) program establishes a mandatory NO_X annual emissions cap for stationary facilities in the HGB area located at sites with a collective uncontrolled design capacity to emit 10 tons per year or more of NO_X. The MECT program source population is relatively small but very diverse and covers, among others, EGUs, refineries, chemical plants, and industrial and commercial boilers. The diverse source population allows the MECT program to be a viable means of reducing NO_X emissions without impacting electric reliability. Overall, the MECT program has not encountered major problems caused by its small size and has resulted in environmental benefits for the HGB area.

The MECT program establishes a hard cap for NO_X emissions at a level modeled as necessary for the area to reach ozone attainment. The MECT program started January 1, 2002 and the NO_X cap stepped down each subsequent year until reaching the final cap level of 80 percent of the baseline NO_X emissions in January 2007. In the MECT program one allowance is equivalent to one ton of NO_X emissions. Allowances are allocated to existing facilities on January 1 of each control period, which spans the calendar year. Facilities that do not receive allowances as "existing facilities" (those in operation at the time of program inception) must purchase excess allowances from other covered sources to operate and demonstrate compliance. All covered sources are required to hold sufficient allowances at the end of each control period to equal NO_X emissions during the same time period. Allowances can be used in the control period of allocation, traded to another covered source in the MECT for use in the same time period, or banked for use in the following control period.

Allowances can be traded in one of four ways: Vintage trades, current year trades, individual future year trades, or stream trades. Vintage trades involve the immediate transfer of vintage allowances. Current year trades involve the immediate transfer of current allowances. Individual future year and stream trades involve the transfer of future allowances, with stream trades involving a transfer of allowances in perpetuity. Analysis conducted by the Texas Commission on Environmental Quality of the MECT program trading history shows that approximately 20 percent of the allowances allocated each year are traded and that nearly 50 percent of all program participants have participated in allowance trading. Allowance prices are set by market demand. Prices of individual year allowances have steadily increased as the program has progressed, showing that the value of the allowances increases as the cap tightens. Stream trade prices have fluctuated throughout the program, but have steadily increased as the final cap level has been reached.

(2) Regional Clean Air Incentives Market (RECLAIM)

In comparison to MECT, RECLAIM is a small trading program that has faced a number of challenges due to initial program design decisions. In 1994, RECLAIM established a cap and trade program for NO_X and SO_2 emissions as part of an effort to improve air quality in the Los Angeles area. Every year the caps decline to meet the objective of getting the area into compliance with ozone and particulate matter NAAQS. One noteworthy feature of the RECLAIM trading programs is the two overlapping cycles. Roughly equal numbers of facilities were assigned to each of the two compliance cycles. Facilities in compliance cycle 1 complete their twelve month cycle at the end of the calendar year (December 31), while facilities in compliance cycle 2 complete their twelve-month cycle at the end of the fiscal year (June 30). Around 300 facilities have participated annually in the RECLAIM NO_X trading program. Every facility then complied using valid credits of either cycle, but banking of allowances for use in a later period was not allowed.

RECLAIM Trading Credits (RTC) prices for NO_X rose from about $3,000 per ton early in 2000 to nearly $20,000 per ton in June and up to about $70,000 per ton in August of that year. Prices of RTCs during the California energy crisis during 2000 and 2001 averaged in the $50,000 per ton range.[102] While the California crisis was the result of several malfunctions in the market, the RTC price spike was exacerbated by a number of factors starting with the fact that few emissions reductions had been made in earlier years. Prior to the California crisis, RTCs had been over-allocated, RTC prices had remained low, and utilities had taken little action to install costly controls. When emissions increased and exceeded the level of allocated RTCs, prices shot up to very high levels. In addition, there has been speculation that high RTC prices at the time were partly caused by the high demand for credits resulting directly from the manipulation of the power market by generators.[103]

The operation of the RECLAIM market also contributed to the high prices in the overall power markets. During this period, generators would pay excessively high prices for RTCs in order to raise the price of southern California generation needed to meet demand in the California Independent System Operator (CAISO). Subsequently, generation with high RTC costs in the RECLAIM area would be used to set the electricity price for all of California. The result was that generators could then collect excessive profits on their generation located outside the RECLAIM area. In addition, RECLAIM's overlapping compliance cycles and assignment of facilities to one of two compliance cycles appears to have contributed to some confusion among the participants in the markets.[104] Since that time, significant changes have been adopted to improve the program.

According to the audit report for the 2007 compliance period, total aggregate NO_X emissions were below total allocations by 21 percent and total aggregate SOX emissions were below total allocations by 13 percent. Since January 2008, NO_X RTCs prices have been declining and have not exceeded $15,000 per ton.

[102] Joskow, Paul and Edward Kahn, 2002. A Quantitative Analysis of Pricing Behavior In California's Wholesale Electricity Market During Summer 2000: The Final Word.

[103] Kolstad, Jonathan T. and Frank A. Wolak, 2003. Using Environmental Emissions Permit Prices to Raise Electricity Prices: Evidence from the California Electricity Market. Published by University of California Energy Institute.

[104] Holland, Stephen P. and Michael Moore, 2008. When to Pollute, When to Abate? Intertemporal Permit Use in the Los Angeles NO_X Market. Published by University of California Energy Institute.

f. Why This Is Not the Preferred Option

As explained above, EPA is requesting comment on a State Budgets/Intrastate Trading remedy as an alternative option because this option would provide certainty regarding emissions from each state. However, this option would be more resource intensive, more complex, less flexible, and potentially more susceptible to market manipulation than the other options on which EPA is taking comment.

Although this remedy may be perceived as relatively easy to understand and follow, it would actually be more burdensome to administer due to the number of trading programs that would be required to operate simultaneously and annual auctions that would be held every year to address the issues of market power within states. It would also result in a greater burden for participants operating EGUs in several states. Finally, EPA is asking for comment on whether this option raises electric reliability issues since sources would have less flexibility and fewer options for compliance. EPA is requesting comments on this approach, specifically on alterations that could address the drawbacks identified above or on any other weaknesses of this option not identified by EPA. EPA also welcomes comments regarding the validity of the concerns with this approach identified above.

6. Direct Control Remedy Option

The second alternative option on which EPA is requesting comment is the direct control option described in this section. EPA is considering the relative merits of this option and requests comment on whether a direct control remedy option should be included in the final FIPs.

There are a variety of ways to construct a direct control option. The approach that EPA is presenting as an alternative to the remedy in the proposed FIPs would assign emissions rate limits to individual sources. Emissions limits would take the form of input-based emissions rate limits (lb/mmBtu).

EPA requests comments on the direct control remedy summarized later and the approach for determining emissions rate limits, which is described in greater detail in the "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD in the docket for this rulemaking. Specifically, EPA requests comment on the general use of a direct control remedy as well as the specific rate-based direct control approach described later. EPA also requests comment on the potential weakness of this remedy option identified in the discussion later. In addition, EPA requests comment on alternate methodologies which could be used to implement a direct control remedy.

See section V.E. later for projected costs and emissions associated with this option.

a. Description of Option

Unlike the proposed remedy option (State Budgets/Limited Trading) and the other alternative remedy option (Intrastate Trading) discussed previously, which both use flexible cap-and-trade approaches, a direct control remedy would directly regulate individual sources. Under this direct control remedy alternative, each owner of EGUs would be required to meet specified average emissions rate limits covering all of its EGUs in each covered state. In a state covered for the 24-hour and/or annual $PM_{2.5}$ NAAQS, the direct control remedy option would require each company within the state to meet specified EGU annual emissions rate limits for SO_2 and NO_X. In a state covered for the 8-hour ozone NAAQS, this remedy would require each company within the state to meet specified EGU ozone season emissions rate limits for NO_X. EPA would set emissions rates on a unit-by-unit basis in all covered states (*see* approach to determine emissions rate limits, later).

While emissions rates in all states would be set on a unit-by-unit level, a company would be allowed to average the emissions at its units within each state to meet the specified within-the-state rate limits. Company-level average rates would be calculated as company-level total emissions divided by company-level total heat input in each state. Analogously, allowable company-level average rates would be calculated using unit-specific rate limits and the heat inputs used to determine those allowable rates (as discussed in 6.b.1). A company that exceeded the applicable average rate limits would be subject to penalties (described later).

In addition, to address the potential variability in annual emissions associated with emissions rate limits (*i.e.*, not all years are average), starting in 2012, each state's total annual (or ozone season, as applicable) EGU emissions would also be capped. Emissions from EGUs in each state would be limited to the state's emissions budget with the variability limit. Each state's EGU emissions would be capped in the following two ways. First, the state's EGU emissions would not be permitted to exceed the state budget with the state's 1-year variability limit in any year (or ozone season, as applicable). Second, on average, the state's EGU emissions would not be permitted to exceed the budget with the state's 3-year variability limit, evaluated as a 3-year rolling annual (or ozone season) average (or, in SO_2 group 1 states during 2012 and 2013, a 2-year rolling average). *See* section IV.E for lists of each state's emissions budgets. Section IV.F describes EPA's proposed approach to variability. Tables IV.F–1 through IV.F–3 present 1-year and 3-year variability limits. Table IV.F–4 presents 1-year and 2-year variability limits for SO_2 group 1 states during 2012 and 2013.

If total EGU emissions in a state exceed either of these limits (*i.e.*, budget with 1-year variability limit in any year, or budget with 2-or 3-year variability limit on average), then each company with units in the state whose emissions in the state exceeded the company's share of the state budget with variability limit would be subject to a penalty. These assurance provisions are designed to assure that emissions in each covered state do not exceed the state's budget with variability limit. They are described later. EPA also believes the penalty provisions described later are sufficient to ensure that these caps would not be exceeded.

To implement this remedy option, EPA would determine unit-level emissions rate limits for SO_2, NO_X annual, and NO_X ozone season at levels such that, if the units operated at the levels assumed in determining the state budgets, total emissions of each pollutant from these units would sum to each state's emissions budget for the pollutant without the variability limit. The method for determining these rate limits is described later.

An alternative direct control approach would be to create individual unit-level annual emissions caps (*e.g.*, tons/year) in order to cap emissions in each state. However, this approach would greatly limit operational flexibility and increase risk to electric reliability. For example, a unit-level annual emissions cap approach could prevent a peaking unit from running at a time when the unit is necessary for electric reliability. EPA does not believe that a unit-level annual emissions cap approach is workable.

b. How the Option Would Be Implemented

(1) Approach To Determine Emissions Rate Limits

To implement this remedy option, EPA would determine unit-level emissions rate limits for SO_2, NO_X annual, and NO_X ozone season, for covered EGUs in the covered states.

Emissions rate limits would be set at levels such that, if the units operated at the levels assumed in determining the state budgets, total emissions from these units would sum to the state budgets. In a state covered for purposes of the $PM_{2.5}$ NAAQS, EPA would determine SO_2 and NO_X annual emissions rate limits for each covered EGU. In a state covered for purposes of the 8-hour ozone NAAQS, EPA would determine NO_X ozone season emissions rate limits for each covered EGU.

Emissions rate limits for Phase I (2012 and 2013). State budgets were derived from the lower of available 2007–2009 quarterly emissions or IPM base case projections for 2012, at the state level. Analogous to state budget calculation, EPA would base the Phase I annual emissions rate limit on either the unit's reported annual emissions rate or the IPM projected rate. Rates based on reported data would be calculated using the most recent first, second, third, and fourth quarters of emissions data reported to EPA, between the first quarter of 2007 and the third quarter of 2009, where four such quarters of reported data are available. EPA would determine ozone season rates based on a unit's most recent ozone season emissions reported to EPA during the period of 2007–2009, if available, and projections or source-specific judgments otherwise.

For units where EPA is aware that SO_2 or NO_X controls will be installed by 2012 and such controls were not reflected in the unit's reported emissions rate as determined previously (*i.e.*, the control was not in operation during the period of time on which emissions limits were based), EPA would determine the Phase I emissions rate limit as the historic rate adjusted (reduced) to reflect operation of the planned control equipment at an emissions rate consistent with operation of that equipment. Emissions rate limits would be determined based on the assumption that units operate all existing SO_2 and NO_X control equipment, and the assumption that the type of fuel used does not change from that used in determining the unadjusted rate limit.

For those EGUs which did not report a first, second, third, and fourth quarter of SO_2, NO_X, and/or a complete ozone season of NO_X emissions data to EPA during the 2007–2009 period, or for those units located in states where budgets are based on IPM projections, EPA would determine emissions rate limits based on modeling projections. Based on the analysis conducted for this proposed rule, EPA would use modeling projections to determine SO_2 rates for approximately 1,600 units, annual NO_X rates for 1,800 units, and ozone season NO_X rates for 1,900 units. EPA seeks comment on the ability of all such units to achieve these limits based on IPM projections. *See* table entitled "Phase I and Phase II unit-level emission rate limits" located in the "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD in the docket for this rulemaking.

For those units that did not report data for a given pollutant and time frame combination and also were not included in IPM modeling, EPA would need to determine permissible rates based on unit characteristics (*e.g.*, types and sizes of units, fuel type). The approach would also need to take into account the variety of controls and measures that can be used to limit emissions, including available fuels. While EPA does not believe that such units exist, EPA is taking comment on the existence of units that did not report first, second, third, and fourth quarter data to EPA between the first quarter of 2007 and the third quarter of 2009, and are not included in IPM modeling. If EPA is made aware of such units, the unit-level analysis required to establish such limits would be extremely complex, and could impact the ability of EPA to require the reductions as quickly as under other remedy approaches.

EPA is also taking comment on an alternative approach for setting emissions rate limits for those units which did not report a first, second, third, and fourth quarter of SO_2, NO_X, and/or a complete ozone season of NO_X emissions data to EPA during the 2007–2009 period. In this alternative approach, EPA could develop specific limits that would apply to a large group of units with varying characteristics. The numerous variables that contribute to differences in units" emissions rates complicate development of limits for a large group of units. Therefore, to ensure that all units in a broadly-defined group could achieve their rate limits, it would be necessary to either establish limits that are fairly weak so that the poorest-performing units could meet the requirements ("lowest-common-denominator" effect), or, design more stringent requirements but include provisions for exceptions to the requirements. At this time, EPA believes using IPM projections and source-specific judgments is preferable to the alternative of group-based limits, and seeks comments on this alternative.

Emissions rate limits for Phase II (2014 and onward). For EGUs in states that are in SO_2 group 1 (*i.e.*, the more stringent SO_2 group), EPA would further adjust (reduce) SO_2 emissions rates for certain EGUs that EPA projects would install FGD in modeling of the proposed remedy option (at less than $2000 per ton); for such units EPA would determine emissions rate limits at rates consistent with FGD operation. For other covered units, Phase II emissions rate limits would be the same as Phase I limits. Again, emissions rate limits would be determined based on the assumption that units operate all existing SO_2 and NO_X control equipment, and that the type of fuel used does not change from that used in determining the unadjusted rate limit. Note that for ozone season NO_X there is only one phase.

Emissions rate limits for new units. The emissions rate limits for covered new units would be set equal to the permit rates for these units.

EPA has calculated specific emissions rate limits for each existing unit that would be covered under this direct control remedy option. These unit-level emissions rate limits appear in a table entitled "Phase I and Phase II unit-level emissions rate limits" located in the "State Budgets, Unit Allocations, and Unit Emissions Rates" TSD in the docket for this rulemaking. More detailed description of the approach is also provided in the TSD. EPA is requesting comment on this approach for determining the emissions rate limits described in the TSD and on the limits themselves.

(2) Applicability

Applicability would be the same for all three remedies. Refer to section V.D.4 previously for detailed discussion on applicability.

(3) Monitoring and Reporting

Monitoring provisions would be the same for all three remedies. The direct control option would require minor changes to the reporting and record keeping requirements due to the need to collect information on both emissions rates and mass. The provisions would require complete, accurate measurement and timely reporting of emissions to assure accountability and provide public access to data. Refer to section V.D.4 previously for detailed discussion on monitoring and reporting requirements.

(4) Assurance Provisions

As discussed previously, starting in 2012, the direct control remedy alternative would include assurance provisions designed to assure that emissions in each covered state do not exceed the state's emissions budget with variability limit. The state's EGU emissions would not be permitted to exceed the state budget with 1-year variability limit in any year (or ozone season, as applicable). Additionally, on a 3-year rolling average basis, the state's EGU emissions would not be permitted to exceed the budget with the 3-year variability limit (evaluated on an annual or ozone season basis, as appropriate). Furthermore, during 2012 and 2013, SO_2 emissions from EGUs in group 1 states (*i.e.*, the more stringent SO_2 group) would not be permitted to exceed the budget with the state's 2-year variability limit, evaluated as a 2-year rolling annual average. Section IV.E in this preamble lists each state's emissions budget, and section IV.F lists the 1-, 2-, and 3-year variability limits, as applicable.

Note that for EGUs in states that are in SO_2 group 2 (*i.e.*, the less stringent SO_2 group) and/or states required to reduce NO_X emissions, EPA would apply only the 1-year variability limit in 2012 and 2013, and not a 2-year variability limit. Because emissions would be evaluated against the 3-year variability limit on a 3-year rolling average basis, the application of the 3-year variability limit in 2014 would also serve to limit emissions in 2012 and 2013. For EGUs in SO_2 group 1 states (*i.e.*, the more stringent SO_2 group) EPA would apply a different 1-year SO_2 variability limit in 2012 and 2013 than for 2014 and later. Furthermore, in these group 1 states, EPA would apply a 2-year SO_2 variability limit in 2012 and 2013, and a 3-year limit for later years (section IV.F discusses why variability limits for the group 1 states would differ in 2012 and 2013).

If total EGU emissions in a state exceed either the state's budget with 1-year variability limit in any year, or budget with 3-year variability limit (or 2-year limit, as appropriate) on average, then each company with units in the state whose emissions in the state exceeded its share of the state budget with variability limit would be subject to a penalty for its share of emissions above the budget with variability limit.

In the State Budgets/Limited Trading remedy described previously, the proposed assurance provisions include an allowance surrender requirement. Those assurance provisions would require a company to surrender one allowance for each ton of the company's proportional share of the amount the state's EGU emissions exceed the budget with variability limit. This allowance surrender requirement is in addition to the trading program requirement to surrender one allowance for every ton emitted.

In the direct control alternative, however, allowances are not allocated to units therefore an allowance surrender requirement is not feasible. Instead, for this alternative, a company with emissions over its share of the budget with variability limit would be in violation of the CAA and subject to discretionary penalties. The tonnage amount of the company's violation, *i.e.*, the company's excess emissions under the assurance provisions, would be its proportional share of the amount that the state's EGU emissions exceed the budget with the variability limit. Each ton of the company's excess emissions, as well as each day in the averaging period, would be a violation.

In this direct control remedy alternative, a company's share of the state budget with variability limit would be determined using the same approach described in the State Budgets/Limited Trading option, previously. That approach is based on allowance allocations; although the direct control remedy would not allocate allowances to sources, this remedy would use the allocation method described in State Budgets/Limited Trading in determining a company's share of the state budget.

The assurance provisions would commence in 2012 for this direct control option. In contrast and for the reasons explained in section V.D.4, for the proposed State Budgets/Limited Trading remedy, EPA is proposing to start applying the assurance provisions in 2014. The combination of circumstances for State Budgets/Limited Trading—known locations of controls and a price on each ton emitted—provides greater certainty of where reductions will occur during 2012 and 2013 than would be provided by the direct control program. In contrast to the State Budgets/Limited Trading remedy, the direct control program does not put a price on emitting SO_2 or NO_X so does not provide that incentive to reduce emissions. Sources can increase generation, while meeting the emissions rate limits, and increase their emissions. For these reasons, the direct control program provides less certainty regarding the location of emissions in the short term. For this reason, EPA believes that it would be appropriate to apply the assurance provisions under this remedy option beginning in 2012.

EPA requests comment on these assurance provisions.

(5) Penalties

As explained previously, under this direct control remedy approach, each owner of EGUs within a covered state would be required to meet specified average emissions rate limits for SO_2 and/or NO_X emission for all of its EGUs. For the annual SO_2 or NO_X control programs, if a company were to exceed the applicable company-wide annual average rate limit, the company would be in violation of the CAA and subject to discretionary civil penalties.

The excess emissions of the owner's EGUs would be calculated as the EGUs" actual annual average emissions rate minus the applicable annual average emissions rate limit, with the difference multiplied by the EGUs" total actual annual heat input. Each ton of excess emissions, as well as each day in the averaging period (*e.g.*, 365 days for an annual program), would be a violation of the CAA. The maximum discretionary penalty under CAA Section 113 is $25,000 (inflation-adjusted to $37,500 for 2009) per violation.

For the ozone season NO_X program, the penalty provisions would work in the same manner described herein except on an ozone season basis rather than annual.

In addition, any company with EGU emissions exceeding its share of the state budget with variability limit for SO_2, NO_X annual or NO_X ozone season would also be in violation of the CAA and subject to discretionary civil penalties explained earlier in this section if, in any year (or ozone season, as applicable), the state as a whole exceeds its budget with variability limit (*see* description of assurance provisions, previously).

EPA requests comment on the penalty provisions.

c. How the Direct Control Remedy Is Consistent With the Court's Opinions

The direct control remedy option would implement the section 110(a)(2)(D)(i)(I) requirement that "emissions from sources that contribute significantly and interfere with maintenance in downwind nonattainment areas" be prohibited. It would do so by establishing for covered EGUs specific emissions rate limits, with company-wide within state averaging. Emissions rates in all states would be set on a unit-by-unit basis at levels such that, if the units operated at the levels assumed in determining the state budgets, total emissions from these units would sum to each state's emissions budgets without the variability limits. A company could average the emissions at its units within each state to meet specified within-the-state rate limits. This approach would directly limit emissions from EGUs in each covered state, providing assurance that emissions reductions would occur within each state consistent with the mandate of section 110(a)(2)(D)(i)(I).

Because individual EGUs would be required to meet specific emissions rate limits (with within-state company-wide averaging), this option would ensure that required controls and measures are installed and implemented within the state. The fact that emissions, after implementation of all controls required to meet the emissions rate limits, may vary based on the amount of generation in each state is not inconsistent with the section 110(a)(2)(D)(i)(I) requirement that all significant contribution and interference with maintenance be eliminated. As noted previously, changes in generation due to changing meteorology, demand growth, or disruptions in electricity supply from other units can all affect the amount of generation needed in a specific state and thus the baseline emissions from that state. Because baseline emissions are variable, emissions after the elimination of all significant contribution are also somewhat variable.

Further, any such variation in emissions would be limited. As with the State Budgets/Limited Trading option described previously, no state's EGU emissions would be permitted to exceed the state budget with variability limit in any year (or ozone season, as applicable). Nor would any state's EGU emissions be permitted, on average, to exceed the budget plus a specified portion of the state's variability limit, evaluated as a 3-year rolling annual (or ozone season) average (or, in SO_2 group 1 states during 2012–2013, a 2-year rolling annual average). Section IV in this preamble lists each state's emissions budget, and 1-, 2-, and 3-year variability limit, as applicable.

d. Electric Reliability Issues

The risk to electric reliability is considered low under the direct control remedy option. Specifically, the provisions for the variability limits and company averaging within each state help to alleviate electric reliability concerns. Therefore, EGUs are expected to be able to both comply with their emissions rate limits and reliably provide electricity to customers. EPA requests comment on electric reliability issues.

e. Why This Is Not the Preferred Option

As explained previously, EPA is requesting comment on the merits and weaknesses of this direct control remedy option. EPA did not include this remedy option in the proposed FIPs; however, we continue to consider this option and are taking comment on whether this option should be included in the FIPs. This option would provide assurance that companies in each state are meeting specific emissions rate limits and would also ensure that annual emissions from each state are capped. Additionally, the direct control option may be perceived as easy to understand and follow. Nonetheless, at this time, EPA believes the direct control option is inferior to the preferred approach. EPA requests comments on the validity of EPA's concerns regarding this option and alternative methods for addressing those concerns.

EPA modeling projects fewer emissions reductions under the direct control alternative than the proposed State Budgets/Limited Trading remedy. Additionally, the reductions would be achieved at a higher cost than the proposed remedy. *See* section V.E. for projected costs and emissions.

A direct control program must account for outliers, *e.g.*, units that can not install controls due to space limitations. EPA believes that the within-the-state company-wide averaging in the direct control alternative on which EPA is taking comment likely mitigates this concern. However, this averaging approach may put an owner with a small number of units within a state at a disadvantage compared to an owner with a larger number of units. EPA requests comment on this issue.

Within the direct control approach on which EPA is taking comment, the assurance provisions (which limit a company's emissions within a state to its share of the budget with the variability limit if the state's budget with variability limit is exceeded) may also put an owner with a small number of units at a disadvantage compared to an owner with a larger number of units within a state. EPA seeks comment on this issue.

A direct control program based on emissions rate limits does not cap annual emissions; if there is growth in fossil generation within a state, a rate-based approach alone could allow emissions increases. In the direct control approach on which EPA requests comment, the assurance provisions provide some assurance of achieving required reductions.

Notably, the direct control approach described herein restricts compliance options more than a trading approach. EPA generally believes that granting more flexibility to companies in meeting an emissions reductions goal results in the ability of those companies to meet that goal at a lower cost and decreases reliability risks in the electric power system. While some portion of this effect is captured in IPM modeling (*see* section V.E. for projected costs and emissions), some types of unforeseen innovations in technology, fuel switching, and management cannot be captured by modeling. Any potential innovations and resulting cost savings are more likely to be found and utilized in the presence of regulatory flexibility. Based on historical experience, EPA believes that the benefits offered by a flexible trading approach are large and should be considered qualitatively, even if they cannot be quantified. Many of these benefits would be foregone under the direct control approach.

E. Projected Costs and Emissions for Each Remedy Option

Emission and cost projections for the three remedies discussed previously come from the Integrated Planning Model (IPM), a dynamic linear programming model of electric generation in the contiguous U.S. For each remedy, projected costs relative to the base case appear in Table V.E–1. The following section explains these projections in light of how the remedies differ and how they were represented in the model. The emissions projections below comprise fossil generation above 25 megawatts of capacity, the units that would be subject to the rule. More detail on the modeling of costs and emissions can be found in the Regulatory Impact Analysis for the proposed Transport Rule and in the IPM Documentation.

TABLE V.E–1—PROJECTED INCREMENTAL COSTS DUE TO TRANSPORT RULE REMEDIES COMPARED TO BASELINE WITHOUT TRANSPORT RULE OR CAIR

[Billion 2006 dollars]

	2012	2014	2020	2025
Limited Interstate Trading (proposed)	3.7	2.8	2.0	2.0
Intrastate Trading	4.2	2.7	2.2	2.2
Direct Control	4.3	3.4	2.5	2.3

1. State Budgets/Limited Trading

The proposed remedy of State Budgets/Limited Trading was modeled with regional emissions caps beginning in 2012 and state-specific emissions limits beginning in 2014. The state-specific emissions limits represent state budgets plus 3-year average variability limits. Because banking early reductions beyond the budget levels is allowed, 2012 SO_2 reductions are greater overall than state budgets alone would require in that year. Table V.E–2 shows the projected emissions reductions from this remedy.

TABLE V.E–2—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSIONS REDUCTIONS IN COVERED STATES WITH THE TRANSPORT RULE COMPARED TO BASELINE WITHOUT TRANSPORT RULE OR CAIR

[Million tons]

	2012 base case emissions	2012 transport rule emissions	2012 emissions reductions	2014 base case emissions	2014 transport rule emissions	2014 emissions reductions
SO_2	8.4	3.4	5.0	7.2	2.6	4.6
Annual NO_X	2.0	1.3	0.7	2.0	1.3	0.7
Ozone Season NO_X	0.7	0.6	0.1	0.7	0.6	0.1

2. State Budgets/Intrastate Trading

Though based on the same state budgets as State Budgets/Limited trading, the alternative remedy of State Budgets/Intrastate Trading costs approximately 0.5 billion 2006 dollars more in 2012 and achieves slightly more SO_2 reduction in 2012 (and slightly less in 2014), as Table V.E–3 shows. In modeling this remedy, each state's emissions were restricted to the state budget without variability. Without the opportunity for even limited trading of allowances across state borders, more banking was projected in some states. In other states, more immediate emissions reductions (relative to the base case) are projected so that state budgets are met exactly. Both of these factors drive 2012 costs higher than those of limited interstate trading and lead to slightly greater SO_2 reductions in 2012.

TABLE V.E–3—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSIONS REDUCTIONS IN COVERED STATES WITH THE INTRASTATE TRADING ALTERNATIVE REMEDY COMPARED TO BASELINE WITHOUT TRANSPORT RULE OR CAIR

[Million tons]

	2012 base case emissions	2012 transport rule emissions	2012 emissions reductions	2014 base case emissions	2014 transport rule emissions	2014 emissions reductions
SO_2	8.4	3.2	5.2	7.2	2.7	4.5
Annual NO_X	2.0	1.3	0.7	2.0	1.2	0.8
Ozone Season NO_X	0.7	0.6	0.1	0.7	0.6	0.1

3. Direct Control

The direct control alternative remedy consists of source-specific emissions rate limits commensurate with those used in the derivation of state budgets (see sections IV.D and IV.E). To represent assurance provisions, the emissions from each state were also constrained to the state's budget plus 3-year average variability limit beginning in 2012. For states with more stringent SO_2 budgets in 2014, FGD retrofits were required on units shown to have cost-effective retrofit opportunities at $2,000 per ton.

Compared to the proposed remedy of State Budgets/Limited Trading, the direct control alternative costs approximately 0.6 billion 2006 dollars more and results in less SO_2 reduction in 2012, as shown in Table V.E–4. Unlike remedies allowing banking for early reductions, the direct control alternative does not result in reductions below state budgets in 2012. At the same time, meeting specific rate requirements for every source means there is little incentive to achieve additional reductions with fuel switching.

TABLE V.E–4—PROJECTED SO_2 AND NO_X ELECTRIC GENERATING UNIT EMISSIONS REDUCTIONS IN COVERED STATES WITH THE DIRECT CONTROL ALTERNATIVE REMEDY COMPARED TO BASELINE WITHOUT TRANSPORT RULE OR CAIR

[Million tons]

	2012 base case emissions	2012 transport rule emissions	2012 emissions reductions	2014 base case emissions	2014 transport rule emissions	2014 emissions reductions
SO_2	8.4	3.8	4.6	7.2	2.6	4.6
Annual NO_X	2.0	1.3	0.7	2.0	1.2	0.8
Ozone Season NO_X	0.7	0.6	0.1	0.7	0.6	0.1

4. State-Level Emissions Projections

Tables V.E–5, V.E–6, and V.E–7 show projected emissions at the state level from all EGUs in 2014.

TABLE V.E–5—PROJECTED STATE-LEVEL [105] SO_2 EMISSIONS FROM ELECTRIC GENERATING UNITS IN 2014

[Tons]

	Base case	State budgets/ limited trading	State budgets/ intrastate trading	Direct control
Alabama	322,362	172,430	162,103	172,430
Connecticut	6,160	3,234	3,208	3,208
Delaware	8,079	9,185	8,974	9,110
District of Columbia	176	179	180	180
Florida	194,723	139,805	159,120	135,366
Georgia	173,257	92,375	89,706	92,375
Illinois	200,484	164,741	156,049	163,902
Indiana	804,425	240,730	267,564	239,852
Iowa	163,966	102,419	102,096	106,569
Kansas	65,125	51,248	52,501	53,275
Kentucky	739,595	123,837	128,318	123,833
Louisiana	94,866	94,933	92,647	96,390
Maryland	45,294	45,449	45,304	45,752
Massachusetts	17,265	10,306	8,595	8,909
Michigan	275,961	173,828	188,796	172,986
Minnesota	62,033	49,413	49,836	58,925
Missouri	500,649	192,645	190,815	190,532
Nebraska	115,695	75,095	73,219	75,061
New Jersey	39,721	16,562	14,935	16,569
New York	142,762	58,455	53,373	58,455
North Carolina	140,924	97,262	109,385	97,262
Ohio	841,199	232,964	269,547	228,514
Pennsylvania	974,644	154,852	183,276	154,855
South Carolina	156,200	131,232	123,525	131,232
Tennessee	600,071	106,767	100,012	94,078
Virginia	136,573	58,329	51,633	58,330
West Virginia	496,307	127,646	147,580	127,646
Wisconsin	117,397	85,933	87,328	83,709

TABLE V.E–6—PROJECTED STATE-LEVEL ANNUAL NO_X EMISSIONS FROM ELECTRIC GENERATING UNITS IN 2014

[Tons]

	Base case	State budgets/ limited trading	State budgets/ intrastate trading	Direct control
Alabama	118,955	61,793	61,618	61,865
Connecticut	7,991	8,003	7,986	8,004
Delaware	5,790	6,176	6,126	6,074
District of Columbia	933	946	948	948
Florida	196,373	126,155	126,065	94,646
Georgia	48,267	44,461	44,462	44,611
Illinois	80,451	57,589	54,773	57,949
Indiana	201,027	112,502	112,721	108,675
Iowa	68,259	53,072	50,146	52,069
Kansas	79,018	40,020	40,074	39,558
Kentucky	148,551	71,371	71,692	69,882
Louisiana	45,551	37,255	36,594	37,164
Maryland	36,089	36,326	33,778	36,532
Massachusetts	12,650	13,047	12,219	13,064
Michigan	98,941	65,066	65,973	67,525
Minnesota	55,283	38,969	39,114	38,039
Missouri	83,019	67,475	61,679	67,648
Nebraska	53,029	35,101	34,105	35,457
New Jersey	27,127	23,377	23,358	23,338
New York	36,352	36,592	34,538	36,597
North Carolina	62,608	60,516	54,639	60,517
Ohio	164,947	99,358	95,997	100,886
Pennsylvania	204,950	123,629	123,095	123,409

[105] The modeling presented in Tables V.E–5, V.E–6, and V.E–7 differs from the proposed Transport Rule because the District of Columbia (DC) is included neither in the annual SO_2 and NO_X requirements nor in the ozone season NO_X requirement. Modeled units in DC include two small facilities, one of which has only units below 25 MW capacity. EPA believes the addition of emissions limits in DC would have little to no effect on the modeling results.

TABLE V.E–6—PROJECTED STATE-LEVEL ANNUAL NO_X EMISSIONS FROM ELECTRIC GENERATING UNITS IN 2014—Continued

[Tons]

	Base case	State budgets/ limited trading	State budgets/ intrastate trading	Direct control
South Carolina	47,742	34,735	33,781	34,616
Tennessee	68,914	28,212	26,874	28,873
Virginia	37,485	35,805	35,745	37,004
West Virginia	100,095	48,180	48,987	50,555
Wisconsin	54,515	41,875	42,498	42,450

TABLE V.E–7—PROJECTED STATE-LEVEL OZONE-SEASON NO_X EMISSIONS FROM ELECTRIC GENERATING UNITS IN 2014

[Tons]

	Base case	State budgets/ limited trading	State budgets/ intrastate trading	Direct control
Alabama	26,995	26,727	26,552	26,823
Arkansas	21,667	12,080	12,095	12,077
Connecticut	3,446	3,453	3,446	3,446
Delaware	2,367	2,669	2,671	2,613
District of Columbia	391	397	397	398
Florida	94,686	62,221	62,037	48,170
Georgia	21,947	19,686	19,688	19,749
Illinois	24,167	24,930	22,833	24,701
Indiana	49,023	47,477	47,813	45,589
Kansas	34,537	17,470	17,590	17,282
Kentucky	29,927	29,376	29,671	29,107
Louisiana	21,443	17,388	17,106	17,308
Maryland	15,307	15,454	14,275	15,512
Michigan	29,934	27,778	28,052	29,415
Mississippi	16,955	8,524	8,526	8,522
New Jersey	10,470	10,324	10,295	10,260
New York	17,257	17,493	16,518	17,491
North Carolina	27,018	26,117	23,459	26,004
Ohio	44,753	41,141	40,051	42,789
Oklahoma	38,546	24,471	24,471	24,426
Pennsylvania	53,263	53,102	52,692	52,586
South Carolina	15,730	14,818	14,666	14,753
Tennessee	12,021	11,868	10,955	12,007
Texas	79,572	68,769	68,874	67,832
Virginia	16,264	15,397	15,289	16,093
West Virginia	24,339	20,249	21,466	21,500

F. Transition From the CAIR Cap and Trade Programs To Proposed Programs

This proposed Transport Rule would replace the CAIR rule and its associated trading programs. This section elaborates on some of the areas of the CAIR program that would need to be addressed in the transition to the new program. EPA is taking comment on how the transition would occur.

1. Sunsetting of CAIR, CAIR SIPs, and CAIR FIPs

The CAIR, CAIR SIPs, and CAIR FIPs would be replaced entirely by the Transport Rule provisions. If this proposed Transport Rule is finalized in 2011, the CAIR, CAIR SIPs, and CAIR FIPs would sunset at the completion of all 2011 control period activities.

In order to implement the sunsetting of the CAIR and CAIR FIPs, the proposed rule includes several revisions of the CAIR, §§ 51.123 and 51.124, and the CAIR FIPs, §§ 52.35 and 52.36. First, sunsetting the CAIR and CAIR FIPs in 2011 would mean that the requirements of the CAIR and CAIR FIPs would not apply to control periods after 2011. Specifically, the CAIR would be revised to rescind, with regard to any control period beginning after December 31, 2011, the findings that states must revise their SIPs to meet CAIR requirements. Similarly, the CAIR FIPs would be revised to state that, with regard to any post-December 31, 2011 control period, CAIR FIP requirements would not be applicable.

Second, the sunsetting in 2011 would mean that the CAIR trading programs would not continue past 2011. Consequently, the proposed revisions of the CAIR and CAIR FIPs would state that, with regard to any post-December 31, 2011 control period, the Administrator would not carry out any of the functions established for the Administrator in the CAIR model trading rule, the CAIR FIPs, or any state trading programs approved under the CAIR.

Third, the sunsetting in 2011 would mean that CAIR allowances allocated for control periods after 2011—which have already been recorded by the Administrator in the Allowance Management System compliance accounts of sources in many states—would not be usable in the CAIR trading programs for control periods ending before 2012. Specifically, under the existing CAIR trading programs, a source that fails to hold sufficient allowances to cover emissions for the 2011 control period (whether annual or ozone season) must provide for surrender to the Administrator three allowances (one as an offset and two as an automatic penalty) allocated for the 2012 control period for every one allowance that was not held as required. However, consistent with the proposed termination of the CAIR trading programs for control periods after 2011, EPA believes that allowances allocated for such control periods (*e.g.*, 2012 allowances) should not be usable for any purpose. In any event, because such allowances would have little or no market value, their deduction would impose little or no cost on the party holding them. Consequently, the proposed revisions of the CAIR and CAIR FIPs would state that the Administrator would not deduct, for excess emissions, any CAIR allowances allocated for control periods in 2012 or any year thereafter. These revisions would ensure that no CAIR allowances allocated for post-2011 control periods would be used as an offset of, or an automatic penalty for, excess emissions.

As a result of these proposed revisions of the CAIR and CAIR FIP rules, there would be no offset or automatic penalty deducted for a source that failed to hold sufficient allowances to cover its 2011 control period emissions unless the state SIPs are revised. In order to preserve the deductions for offsets and automatic penalties for 2011 control periods, the CAIR SIPs for most states (*i.e.*, 20 out of the 28 states subject to at least one CAIR trading program) would need to be modified and the modified CAIR SIPs would need to be approved by the EPA —-before EPA conducts the process of determining source compliance after the allowance transfer deadline for the 2011 control periods —in order to change the allocation year of the allowances required to be deducted (*e.g.*, from allowances allocated for 2012 to allowances allocated for 2011). Although EPA's past experience with trading programs strongly suggests that few sources would be out of compliance with the requirement to hold allowances covering 2011 emissions, all of these CAIR SIPs would have to be revised because there is no way to predict which few sources in which few states might be out of compliance in 2011 and the process of revising SIPs is too long to be started while EPA is still determining compliance. In fact, when states needed to revise their SIPs to include the existing requirements of CAIR and submit the revised SIPS to the Administrator, EPA found that states needed up to 3 years to develop and submit SIP revisions, and EPA needed about 6 months to act on the SIP revisions. In light of this experience with SIP revisions under CAIR, EPA believes that it would highly unlikely that all, or even most, state CAIR SIPs could be revised, submitted, and approved in time—even if the SIP revision process were started when a final Transport Rule is promulgated—to change what allowances were to be used for offsets and automatic penalties for excess emissions for the 2011 control periods.

Moreover, any excess emissions for the 2011 control periods would be violations of the state SIPs (or of CAIR FIPs in those states with CAIR FIPs) and of the Clean Air Act and, therefore would be subject to discretionary civil penalties under CAA Section 113. Each ton of excess emissions, and each day in the control period involved (*i.e.*, 365 days for annual control periods and 153 days for the ozone season control period), would be a violation, with a maximum penalty of $25,000 (inflation adjusted to $37,500) per violation. In determining what level of discretionary civil penalties to impose on a source that has excess emissions violations, EPA routinely considers, among other things, whether, and if so what level of, other penalties (*e.g.*, automatic excess emissions penalties) have already been imposed for the same violations, as well as any economic benefit of noncompliance (*e.g.*, the avoidance of the cost of surrendering allowances to cover emissions). See, *e.g.*, 42 U.S.C. 7413(e)(1) (including, as penalty assessment criteria, "payment by the violator of penalties previously assessed for the same violation" and "the economic benefit of noncompliance"). Consequently, EPA believes that, regarding the CAIR 2011 control periods (both annual and ozone season) for which it is not feasible to change the offset and automatic penalty provisions to make them workable, the potential for assessment of significant, discretionary civil penalties would provide a strong incentive for compliance with the allowance-holding requirement and avoidance of excess emissions.

In addition to the previously-described, proposed revisions to §§ 51.123, 51.124, 52.35, and 52.36, certain provisions in part 52 that reflect, state by state, the CAIR SIP revisions and CAIR FIP requirements applicable to each state would need to be revised to implement the sunsetting of the CAIR, CAIR SIPs, and CAIR FIPs. However, the timing for proposal and adoption of revisions to part 52 is necessarily different for the part 52 provisions addressing CAIR SIP revisions and those addressing revisions of the CAIR and the CAIR FIPs themselves.

The part 52 provisions addressing CAIR SIP revisions for the individual states reflect EPA's approval of CAIR SIP revisions adopted and submitted to EPA by the respective states. The first step toward sunsetting those part 52 provisions would be that, if and after the proposed Transport Rule was finalized, the respective states would change their SIPs in order to, among other things, make the CAIR provisions in the SIPs inapplicable to any control period that starts after December 31, 2011. After the submittal by the respective states of these SIP revisions, EPA would review and approve such changes. Consequently, the rule text approving such CAIR SIP revisions would not be included in either the proposed Transport Rule or any final rule based on the proposed Transport Rule, but rather would be proposed and adopted only after the respective states revised their SIPs. As EPA did when transitioning from the NO_X Budget Trading Program to the CAIR NO_X ozone season trading program, EPA will work with states to transition from state CAIR programs to their replacement FIPs or state SIPs. This assistance will be provided through meetings or workshops, web-based references, one-on-one assistance through the EPA regions, etc.

In contrast, the part 52 provisions adopting CAIR FIPs for individual states could be revised, as part of the proposed Transport Rule, to sunset these CAIR FIPs because no state action would be required to accomplish this sunsetting. EPA proposes to revise each state-specific part 52 provision adopting a CAIR FIP—whether for NO_X annual or ozone season emissions or SO_2 emissions—to add a paragraph stating that: with regard to any control period starting after December 31, 2011, the respective CAIR FIP would not apply and the Administrator would not carry out any of the functions set forth for the Administrator in the trading program rules under the CAIR FIP; and the Administrator would not deduct for excess emissions any CAIR allowances allocated for 2012 or any year thereafter. The new, added rule text would be very similar to the proposed rule text revisions to §§ 52.35 and 52.36 and would be essentially the same for each of these state-specific Part 52 provisions. EPA has included in the proposed Transport Rule the proposed rule text making these state-by-state revisions for Delaware, District of Columbia, Indiana, Louisiana, Michigan, New Jersey, Tennessee, Texas, and Wisconsin. These provisions revise all of the state-specific Part 52 provisions adopting CAIR FIPs provisions to make the CAIR FIPs inapplicable to any control period that starts after December 31, 2011 and state that the Administrator would not carry out any functions under the CAIR trading programs during any such control period and would not use any CAIR allowances allocated for any such control period.

2. Change in States Covered

The states covered by the proposed Transport Rule differ slightly from states covered by the CAIR. Namely, as compared with the states covered by the CAIR NO_X ozone season trading program, the states covered by the proposed Transport Rule NO_X ozone season trading program would include Georgia, Kansas, Oklahoma, and Texas and would not include Iowa, Massachusetts, Missouri, and Wisconsin. Further, as compared with the states covered by the CAIR NO_X annual and SO_2 trading programs, the states covered by the proposed Transport Rule NO_X Annual and SO_2 trading programs would include Connecticut, Kansas, Massachusetts, Minnesota, and Nebraska and would not include Mississippi and Texas. (*See* also the discussion in section IV.D. regarding the possibility that the states to which this rule would apply could expand.)

Consequently, sources in some states that would be covered by the proposed Transport Rule would have new allowance holding requirements beginning in 2012, but would not have been subject to the CAIR trading programs. Conversely, sources in some states covered by the CAIR or CAIR FIPs would not be subject to the proposed Transport Rule. To the extent that the CAIR reductions were needed or relied upon to satisfy other SIP requirements, states might need to find alternative ways to satisfy requirements for their SIPs. EPA will work with individual states to identify state-specific options to ensure that necessary reductions needed for other SIP requirements can continue.

3. Applicability, CAIR Opt-ins and NO_X SIP Call Units

Except for the changes in the states covered, the general applicability provisions of the proposed Transport Rule would be essentially the same as the CAIR general applicability provisions, with a few exceptions. First, the proposed Transport Rule does not allow any units to opt into the trading programs. In contrast, under CAIR, states could elect to allow boilers, combustion turbines, and other combustion devices to opt into the CAIR trading programs under opt-in provisions specified by EPA, and a number of states adopted these opt-in provisions. However, currently no units have opted into the CAIR trading programs, and, even in the Acid Rain Program, where opt-in provisions have been in place since 1995, very few units have actually opted in.

Second, under the CAIR trading programs, a state subject to the NO_X SIP Call was allowed to expand the applicability of the CAIR NO_X ozone season trading program in the state in order to include all units subject to the NO_X Budget Trading Program (NBP) under the NO_X SIP Call and thereby to continue to meet the state's NO_X SIP Call requirements. Fourteen states chose to expand the CAIR NO_X ozone season applicability in this way, while six states chose not to expand the applicability and instead to meet their NO_X SIP Call obligations in other ways. In expanding the applicability of the CAIR NO_X ozone season trading program, the fourteen states brought into the program large industrial boilers and turbines (with maximum design heat input greater than 250 mmBtu/ hr) and, in some cases, smaller electric generating units (serving generators with nameplate capacity of 15 through 25 MWe), and generally the CAIR NO_X ozone season budgets in these states were increased to account for these additional sources. In contrast, the proposed Transport Rule NO_X ozone season trading program would not allow for expansion of applicability to include these units currently covered only by the NBP.

There are several factors underlying this difference between the proposed Transport Rule and the CAIR. First, in determining which states are contributing significantly or interfering with maintenance of the ozone NAAQS, the Transport Rule does not cover some states subject to the NO_X SIP Call (*i.e.*, Massachusetts, Missouri, and Rhode Island). Further, the six states that chose under the CAIR to require the necessary NO_X SIP Call reductions through provisions other than the CAIR NO_X ozone season program would not likely be interested in expanding applicability under the Transport Rule NO_X ozone season trading program to cover these units. In addition, EPA has determined that these units as a group did not actually reduce emissions as a result of the NBP or through their inclusion in the CAIR NO_X ozone season trading program. In fact, their current emissions rates are nearly identical to what they were before the NBP started. Moreover, these units as a group had allowances that they did not need for compliance and that were available for trading to other affected units. The Transport Rule, as proposed, does not include these units and does not include provisions for allowing states expand applicability to include them. EPA is taking comment on this approach.

4. Early Reduction Provisions

Substantial emissions reductions have occurred as a result of the CAIR programs. These reductions are greater than were expected when the rule was promulgated. This is evidenced in the banks of allowances that exist in each of the CAIR programs.

a. SO_2 Allowance Bank

The bank of Title IV allowances was more than 12 million tons at the end of 2009. This bank is the result of emissions reductions for Title IV where allowances are used for compliance with the requirement to hold allowances covering emissions and early reductions for the CAIR SO_2 trading program. EPA believes that it is advantageous to minimize sources" use of the Title IV allowance bank if possible and recognizes that, if the bank has minimal future market value, there may be incentive to use as many banked allowances as possible. EPA tracks the SO_2 emissions on a quarterly basis and makes the information available to the public at *http://epa.gov/airmarkets/quarterlytracking.html.*

EPA evaluated whether the Title IV allowance bank could be used in the proposed Transport Rule SO_2 program in any way. One idea presented to EPA was to distribute Transport Rule SO_2 allowances based on the number of Title IV allowances a source has in its bank at the completion of compliance in the last year of the CAIR SO_2 program, thereby incentivizing minimal use, by sources, of Title IV allowance banks and encouraging continued emission control. EPA is concerned that the approach would have significant legal risk for two reasons. First, the Court is likely to view the approach as imposing a significant burden on the use of Title IV allowances and therefore as modifying the authorization provided by such allowances. Second, the Court is likely to view the approach as not related to, much less necessary for, implementation of the section 110(a)(2)(D)(i)(I) mandate to eliminate significant contribution and interference with maintenance. EPA chose instead, under the proposed Transport Rule, to distribute Transport Rule SO_2 allowances in a manner directly linked to its calculation of each state's significant contribution and interference with maintenance and not to use Title IV allowances as a basis for distributing the new Transport Rule allowances. EPA is confident that the approach selected is consistent with the Court's opinion in *North Carolina* v. *EPA*, 531 F.3d 896, 922 (D.C. Cir. 2008). (Additional information on this approach can be found in the docket.) EPA requests comment on whether or not an allowance distribution approach based on the number of Title IV allowances in a given source's account would be consistent with the Court opinion.

EPA proposes that the Transport Rule provisions not allow the use of Title IV allowances either as the basis for allocating Transport Rule SO_2 allowances or directly for compliance with allowance-holding requirements. Thus, there would be no SO_2 allowances carried over into the new SO_2 program. Title IV allowances continue, of course, to be used for compliance with the Acid Rain Program.

b. NO_X Allowance Banks

Assuming that NO_X emissions in 2010 and 2011 are equal to what they were in 2009, the CAIR NO_X ozone season bank would contain over 600,000 allowances (which would equal more than 100 percent of the total of the state budgets under the proposed Transport Rule NO_X ozone season program for 2012), and the CAIR NO_X annual bank would contain about 720,000 allowances (which would equal nearly 50 percent of the total of the state budgets under the proposed Transport Rule NO_X annual program for 2012), after completion of true-up of allowance holdings and emissions for 2011. Estimates of the size of the banks have only recently been made based on reported 2009 emissions data, and the impacts of different approaches to handling the banks have not yet been modeled. However, EPA is concerned about the potential impacts of these approaches. On one hand, allowing pre-2012 CAIR NO_X allowances and CAIR NO_X ozone season allowances to be used in the proposed Transport Rule NO_X programs, and thereby ensuring that the allowances would continue to have some market value in the future, would promote the continuation—in 2010 and 2011—of the reductions that occurred in 2009 under the CAIR NO_X programs. On the other hand, the amounts of the banks are so large that they might significantly reduce the amount of emissions reductions that would otherwise be achieved in the proposed Transport Rule NO_X programs, particularly in the earlier years (*e.g.*, 2012 and 2013).

EPA has identified several possible approaches for handling banked pre-2012 CAIR NO_X allowances in the Transport Rule NO_X programs. The first approach might be to allow all such banked CAIR allowances to be brought into the Transport Rule NO_X programs, make the assurance provisions effective starting in 2012, and rely on the assurance provisions to ensure that each state continues to eliminate all of the significant contribution and interference with maintenance that EPA has identified in today's proposal. The banked CAIR allowances would be usable, and the assurance provisions would apply, in all states in the Transport Rule NO_X programs. However, EPA is concerned that some parties may view this approach as having the effect of allowing sources that were advantaged by the development of state budgets using fuel adjustment factors—the use of which was reversed by the Court in *North Carolina*, 531 F.3d at 918–21—and that still hold part of their allocated allowances to continue have an advantage in the Transport Rule NO_X trading programs. These concerns may be mitigated somewhat by the fact that even though the methodology used to divide the regional budget into state budgets used fuel factors, states had the flexibility to allocate allowances however they wished. EPA takes comment on the extent to which states have allocated differently and the extent to which this may mitigate concerns about allowing the use of banked CAIR NO_X allowances in the Transport Rule annual NO_X and ozone season NO_X trading programs.

The second approach might be to allow only a limited amount of banked pre-2012 CAIR allowances to be brought into the Transport Rule programs. This could be accomplished by allowing all such banked allowances to be used, but at a tonnage authorization level significantly lower than one ton per allowance, in the Transport Rule NO_X programs. However, while severely limiting the tonnage authorization of banked allowances that is allowed into the new programs would limit any advantage realized by sources that received fuel-adjustment-factor-based CAIR allowance allocations, this would also limit any beneficial impact that bringing CAIR allowances into the new programs might have on preserving emissions reductions in 2010 and 2011.

The third option might be to try to factor the bank into the calculation of state budgets by reducing the state budgets to take account of the banked pre-2012 CAIR allowances. This might allow these allowances to be used in the Transport Rule NO_X programs without adversely affecting the states' elimination of the part of significant contribution and interference with maintenance that EPA has identified. However, this approach would not be feasible because EPA cannot determine in advance in which states banked pre-2012 CAIR allowances might be used and so would not know which state budgets should be adjusted and what amount of adjustment would be necessary.

A final approach would simply be to not allow the use of any banked pre-2012 CAIR allowances in the Transport Rule NO_X programs. This approach would avoid the potential legal and practical problems raised by the other approaches and is the approach proposed by EPA. EPA requests comment on the proposed approach, the previously-discussed alternative approaches, and any other possible approaches for handling banked pre-2012 CAIR allowances in the Transport Rule NO_X programs.

5. Source Monitoring and Reporting

Monitoring and reporting using 40 CFR part 75 provisions is required for all units subject to the CAIR programs and would also be required for all units subject to the proposed Transport Rule programs. In states covered by both the CAIR and the proposed Transport Rule, units would generally have no changes to their monitoring and reporting requirements and would continue to monitor and submit reports as they have under the CAIR. The exceptions are units in: CAIR states subject to CAIR NO_X ozone season requirements but NO_X and SO_2 annual requirements under the proposed Transport Rule; or CAIR states subject to CAIR NO_X annual and ozone season and SO_2 requirements but only to NO_X ozone season requirements under the proposed Transport Rule. These exceptions could arise, in part, because under Part 75 some units (*i.e.*, non-Acid Rain units) that are in NO_X ozone season, and not NO_X annual, programs have the option of monitoring and reporting NO_X emissions for just the ozone season.

Units in the following states monitor and report both SO_2 and NO_X year-round under the CAIR and would continue to do so under the Transport Rule: Alabama, Delaware, the District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin. Non-Acid Rain units in Arkansas are currently required to monitor and report NO_X in the ozone season under the CAIR and would continue to be required to do so under the proposed Transport Rule.

Non-Acid Rain units in Connecticut and Massachusetts (about 15 units total) that currently monitor and report NO_X in the ozone season would need to monitor and report NO_X and SO_2 on an annual basis under the proposed Transport Rule.

Non-Acid Rain units in Mississippi (about 4 units) and Texas (about 52 units) are currently monitoring and reporting NO_X and SO_2 year-round and under the proposed Transport Rule would be required to monitor and report NO_X in the ozone season. (All of these units burn natural gas and emitted approximately 12 tons of SO_2 in 2009.)

In states not covered by the CAIR but covered by the proposed Transport Rule, some units would have to meet new monitoring and reporting requirements under part 75. Kansas, Minnesota, and Nebraska are not covered by the CAIR and are covered by the Transport Rule, and units there would need to monitor and report NO_X and SO_2 emissions year-round. Oklahoma is not covered by the CAIR and is covered by the Transport Rule, and units there would need to monitor and report NO_X in the ozone season. There are about 34 non-Acid Rain units total in Kansas, Nebraska and Oklahoma not monitoring and reporting under Part 75 that would need to begin to do so. Most of these units are simple-cycle combustion turbines used in the ozone season as peaking units and would likely be able to utilize the Low Mass Emissions or Appendix D and E methodologies in 40 CFR part 75, which do not require a continuous emissions monitoring system (CEMS). The circulating fluidized bed (CFB) units in Oklahoma (about 4 units) that burn coal are already monitoring and reporting under 40 CFR part 60, subpart Da, which requires an SO_2, NO_X and CO2/O2 (diluent) CEMS. These boilers would only have to add a flow monitor and upgrade the automated data acquisition and handling system. Non-Acid Rain units in Minnesota (about 20 units) would also need to monitor and report, but were already doing so under the CAIR before the CAIR was stayed in Minnesota (74 FR 56721, November 3, 2009); therefore, they would simply have to reactivate those monitoring systems.

Units that have not been covered by part 75 monitoring and reporting in the past would likely have less than one year to install, certify, and operate the required monitoring systems. EPA believes that these units would reasonably be able to comply with this requirement because the monitoring equipment needed is not extensive or is largely in place already for the purpose of meeting other requirements. Quality assurance and reporting provisions and data system upgrades may be necessary, but there would be sufficient time to accomplish this.

G. Interactions With Existing Title IV Program and NO_X SIP Call

1. Title IV Interactions

Promulgation of a Transport Rule would not affect any Acid Rain Program requirements. Any Title IV sources that are subject to final Transport Rule provisions would still need to continue to comply with all Acid Rain provisions. Acid Rain requirements are established independently in Title IV of the Clean Air Act and would not be replaced by the Transport Rule. In contrast with the CAIR, the proposed Transport Rule would not allow Title IV SO_2 allowances to be used in the Transport Rule program. Similarly, Transport Rule SO_2 allowances would not be useable in the Acid Rain Program. Title IV SO_2 and NO_X requirements will continue to apply independently of the Transport Rule provisions. The Transport Rule program as proposed has no opt-in provisions, so no sources, including any that have opted into the Acid Rain Program would be able to opt-in to the Transport Rule program.

Compliance with the Transport Rule would reduce SO_2 emissions in the Transport Rule states below the 2010 Title IV cap. So, as sources complied with the Transport Rule, emissions would go down and with them so would the demand for Title IV allowances. Therefore, the Title IV allowance prices are expected to be very low once the Transport Rule is finalized; some analysts suggest a price of nearly zero. Acid Rain sources will still be required to comply with Title IV requirements, including the requirement to hold Title IV allowances to cover emissions at the end of a compliance year.

There would likely be changes to emissions at some Acid Rain sources outside of the Transport Rule area as a result of the transition from CAIR to the Transport Rule. Namely, emissions at some non-Transport Rule Acid Rain sources may increase because of the change in the Title IV allowance price. This would be expected to occur mainly in the states that border the Transport Rule states. Overall, SO_2 emissions from these non-Transport Rule Acid Rain sources would be expected to increase approximately 237,000 tons each year if the Transport Rule is implemented compared to what they would have been in the absence of the Transport Rule. There is more discussion of this effect in section IV.D.

2. NO_X SIP Call Interactions

States affected by both the NO_X SIP Call and any final Transport Rule will be required to comply with the requirements of both rules. The Transport Rule does not preempt or replace the requirements of the NO_X SIP Call. However, the proposed Transport Rule ozone season program would achieve the emissions reductions required by the NO_X SIP Call from EGUs greater than 25 MW in nearly all NO_X SIP Call states. The NO_X SIP Call states used the NO_X Budget Trading Program (NBP) to comply with the NO_X SIP Call requirements for EGUs serving a generator with a nameplate capacity greater than 25 MW and large non-EGUs with a maximum rated heat input capacity greater than 250 MMBTU/hr. (In some states, EGUs smaller than 25 MW were also part of the NBP as a carryover from the Ozone Transport Commission NO_X Budget Trading Program.) EPA stopped administering the NBP after the 2008 ozone season control period activities, and states used another mechanism to comply with the NO_X SIP Call requirements.

Many of the states using the NBP used the CAIR NO_X ozone season trading program to replace the NBP. To address NO_X SIP Call requirements, fourteen NO_X SIP Call states chose to expand the CAIR NO_X ozone season applicability to include all NBP-affected units. EPA has analyzed the effect of allowing states to expand their CAIR NO_X ozone season applicability and consequently their CAIR NO_X ozone season budgets to include the additional non-CAIR affected NBP units. In 2009, the additional units emitted about half of the amount of allowances added to the CAIR NO_X ozone season budgets for them. The remaining allowances are available for the sources to trade to other affected units. As a group, these units did not reduce their NO_X emissions or their NO_X emissions rates as a result of their inclusion in the CAIR NO_X ozone season program. If EPA were to allow them to be part of the Transport Rule NO_X Ozone Season Program, and if states were allowed to increase the Transport Rule NO_X Ozone Season Budgets by the amounts allowed under the NBP and CAIR for these units, a state's ability to eliminate the part of significant contribution and interference with maintenance that EPA has identified in today's proposal could be jeopardized. One option considered that could possibly address concerns about still being able to address significant contribution and interference with maintenance would be to require the budget increase to be much less than allowed under the NBP and CAIR. For example, the units' 2009 emissions (or 2012 projected emissions if they are required to install controls for another program) could be used to determine the budget increase and the elimination of emissions causing significant contribution and interference with maintenance might be able to be preserved. It is likely the budget changes would not be consistent across states as each state's impact would have to be considered individually. EPA is proposing to not allow the expansion of the applicability of the Transport Rule.

Therefore, the NBP states would need to achieve their NO_X SIP Call emissions reductions another way in order to continue to comply with the NO_X SIP Call. If EPA promulgates a final rule that does not allow the expansion of the Transport Rule to NBP units, any state that allowed these units to participate in the CAIR NO_X Ozone Season Program would need to submit a SIP revision to address their NO_X SIP Call requirement for the reductions.

States that were part of the CAIR NO_X ozone season program or the NBP that are not part of a final Transport Rule ozone season program would need to submit SIP revisions that address the NO_X SIP Call requirements for any emissions reductions that were part of either the CAIR NO_X ozone season program or the NBP and would not continue to be addressed some other way. EPA will work with states to ensure that NO_X SIP Call obligations continue to be met.

VI. Stakeholder Outreach

In early 2009, EPA began its efforts to coordinate activities with state regulatory partners and other stakeholders on the new transport rule to replace CAIR. To establish open lines of communication and ensure transparency in the regulatory process, EPA participated in a series of "listening sessions" in March and April, 2009 with states, nongovernmental organizations, and industry. EPA also participated in tribal teleconferences. The same agenda was set for each of the ten meetings. Meeting notes were developed and distributed for concurrence and to ensure accuracy. Subsequent to these sessions, EPA received post-meeting comments and additional detailed suggestions and analyses on ways to address some of the issues that the court cited, most notably from state regional organizations in the eastern U.S. All the stakeholder-related materials may be found in the EPA docket for the transport rule (EPA–HQ–OAR–2009–0491).

Following the remand of CAIR to EPA in December 2008, 17 states in the East and Midwest, under the umbrellas of the OTC and Lake Michigan Air Directors Consortium (LADCO) with support from southeastern states, worked to develop recommendations for EPA to consider in crafting a new transport rule to replace CAIR. The comprehensive framework presented the consensus approach the states reached but noted that certain regional differences would be addressed in separate letters with additional recommendations and supporting materials.

EPA has considered and appreciates all the ideas and recommendations provided by the states. We are employing the technical work that they submitted as part of the data set we are using in this and later transport rules.

Topics addressed in the listening sessions, where EPA asked stakeholders and regulatory partners for their thoughts on particular issues, included:

- Analysis and baselines.
- Linkages between a state's significant contribution and downwind nonattainment/interference with maintenance.
- Remedies.
- Attainment planning.
- Other areas.

EPA continued to provide updates to regulatory partners and stakeholders through monthly conference calls with states, hosted by, *e.g.*, NACAA, as well as industry and NGO conferences where EPA directors often made presentations.

Several of the options presented in this proposal were influenced by feedback received from stakeholders and regulatory partners, including:

- 2012 baseline used in the calculation of each state's significant contribution and interference with maintenance.
- The "tiered" approach to SO_2 emissions reductions requirements.
- Threshold (1 percent of the NAAQS) used for linking upwind areas to downwind nonattainment and maintenance receptors.
- Approach used to give independent meaning to the interfere with maintenance prong of section 110(a)(2)(D)(i)(I).
- Level of reductions required.
- Use of limited interstate trading.
- Correlated and coordinated requirements and timing for the power industry.

EPA looks forward to the public comment period of this rulemaking and is committed to establishing and maintaining close working relationships with a broad range of public and private sector organizations.

VII. State Implementation Plan Submissions

A. Section 110(a)(2)(D)(i) SIPs for the 1997 Ozone and $PM_{2.5}$ NAAQS

All states have an obligation to submit SIPs that address the requirements of CAA section 110(a)(2) within 3 years of promulgation or revision of a NAAQS. With respect to the 1997 ozone and $PM_{2.5}$ NAAQS, EPA found in 2005 that states had failed to make submissions that address the requirements of section 110(a)(2)(D)(i) related to interstate transport of pollution. *See* 70 FR 21147 (April 25, 2005). Also in 2005, EPA promulgated the CAIR, which was intended to provide states covered by the rule with a mechanism to satisfy their section 110(a)(2)(D)(i)(I) obligations. In the CAIR, EPA concluded that the states in the CAIR region would meet their section 110(a)(2)(D)(i) obligations to address "significant contribution" and " interference with maintenance" requirements by complying with the CAIR requirements. Consequently, states within the CAIR region did not need to submit a separate SIP revision to satisfy the section 110(a)(2)(D)(i) requirements provided they submitted a SIP revision to satisfy CAIR. Most of the CAIR states participated in the CAIR trading programs and submitted SIP revisions that EPA subsequently approved. In 2008, the Court granted several petitions for the review of the CAIR and found, among other things, that EPA had not demonstrated that the CAIR effectuates the statutory mandate of section 110(a)(2)(D)(i)(I). The EPA approvals of the CAIR SIPS preceded the remand of the CAIR by the Court. Therefore, because the D.C. Circuit Court found CAIR and the CAIR FIPs unlawful, EPA's approval of the provisions of a state's SIP submittal as addressing the requirements of the CAIR could not satisfy that state's section 110(a)(2)(D)(i)(I) obligation. In other words, a CAIR SIP submission can no longer be considered an adequate section 110(a)(2)(D)(i)(I) SIP submission. For this reason, EPA's 2005 findings that states had failed to submit SIPs that satisfy section 110(a)(2)(D)(i)(I) [106] remain in force regardless of whether a state covered by the CAIR submitted

[106] The 2005 findings of failure to submit related to states' obligations pursuant to section 110(a)(2)(D)(i). The CAIR, however, addressed only the requirements of 110(a)(2)(D)(i)(I). The remand of CAIR, therefore, had no impact on state SIP submissions or EPA approval of state SIP submissions pursuant to section 110(a)(2)(D)(i)(II).

and/or had an approved SIP stating that compliance with the CAIR satisfied their 110(a)(2)(D)(i) obligations.

The 2005 findings of failure to submit also remain in force for many states not covered by the original CAIR. Some of these states have not yet submitted 110(a)(2)(D)(i)(I) SIPs and thus the findings remain in force. However, several states that were not covered by the CAIR have since 2005 submitted SIP revisions to satisfy the requirements of section 110(a)(2)(D)(i) for the 1997 8-hour ozone and $PM_{2.5}$ NAAQS. Some of these SIPs have been approved and some are pending approval.

For the states that have now been identified to be contributing significantly to nonattainment or interfering with maintenance under this proposed rule and whose 110(a)(2)(D)(i)(I) SIPs with respect to the 1997 ozone and $PM_{2.5}$ NAAQS are pending approval, EPA will finalize the FIP included in this proposed rule only if EPA either determines that the SIP submission is incomplete or disapproves the SIP submission. (Alternatively, if a state withdraws its SIP submission, EPA will finalize the FIP.)

For states which are not included in a final FIP under this proposed transport rule and that have not submitted a 110(a)(2)(D)(i)(I) SIP to address the 1997 ozone and $PM_{2.5}$ NAAQS, a SIP submittal is required.

EPA has approved the 110(a)(2)(D)(i) submission from the state of Kansas for the 1997 ozone and $PM_{2.5}$ NAAQS. The updated modeling done for this proposed rule demonstrates that emissions from Kansas significantly contribute to nonattainment or interfere with maintenance of the 1997 8-hour ozone NAAQS in downwind areas. Because Kansas' current SIP does not prohibit these emissions, it is not adequate to satisfy the requirements of 110(a)(2)(D)(i)(I) at this time. For Kansas, under a separate action, EPA plans to propose a finding under CAA 110(k)(5) (known as a SIP Call) that the state's existing SIP is substantially inadequate to meet the requirements of 110(a)(2)(D)(i)(I) with respect to the 1997 ozone NAAQS. That SIP call, if finalized, would also establish a deadline for submission of a new 110(a)(2)(D)(i)(I) SIP which EPA would review for completeness. Therefore, in today's notice EPA is proposing to finalize the FIP for Kansas for ozone only if the state fails to submit a complete and approvable SIP by the deadline established in any final SIP Call.

B. Section 110 (a)(2)(D)(i) SIPs for the 2006 24-Hour $PM_{2.5}$ NAAQS

With respect to the 2006 24-hour $PM_{2.5}$ NAAQS, EPA has issued a separate **Federal Register** notice finding that a number of states failed to make the required 110(a)(2)(D)(i)(I) SIP submissions. None of the SIP submittals in the states that have submitted section 110(a)(2)(D)(i)(I) transport SIPs for the 2006 24-hour $PM_{2.5}$ NAAQS have been acted on yet by EPA. For the states with SIPs that are pending approval, EPA is proposing to finalize the FIP with respect to the 2006 $PM_{2.5}$ NAAQS only if EPA finds the previously submitted SIP incomplete or disapproves the SIP submission. Alternatively, if any of these states withdraws its 2006 24-hour $PM_{2.5}$ SIP submittal, EPA plans to issue a separate notice of finding for such states.

C. Transport Rule SIPs

EPA also notes that, by promulgating these Transport Rule FIPs, EPA would in no way affect the right of states to submit, for review and approval, a SIP that replaces the federal requirements of the FIP with state requirements. In order to replace the FIP in a state, the state's SIP must provide adequate provisions to prohibit NO_X and SO_2 emissions that contribute significantly to nonattainment or interfere with maintenance in another state or states. The Transport Rule FIPs would be in place in each covered state until a state's SIP was submitted and approved by EPA to replace a FIP.

For each upwind state covered by the proposed Transport Rule, EPA proposes state-specific emissions reductions requirements with respect to one or more of three air quality standards—the 1997 annual $PM_{2.5}$ NAAQS, the 2006 24-hour $PM_{2.5}$ NAAQS, and the 1997 ozone NAAQS. In CAIR, EPA allowed the states to replace the CAIR FIP with SIPs and provided substantial flexibility. Again EPA wants to offer states substantial flexibility for addressing the Section 110(a)(2)(D)(i)(I) transport issues through a SIP should they choose to do so. The EPA's intent is to provide states with substantial flexibility in implementing these emissions reductions requirements. EPA will allow a state to submit a SIP for the ozone requirements only, for the $PM_{2.5}$ requirements only, or for both the ozone and the $PM_{2.5}$ requirements. The specific quantity of emissions reductions necessary for a state's SIP would be determined based on the state emissions budgets provided in the final transport rule. (*See* Tables IV.E–1 for proposed SO_2 and annual NO_X budgets, and IV.E–2 for proposed ozone season NO_X budgets, in section IV.E).

In the states for which EPA is proposing to require reductions with respect to both the 24-hour $PM_{2.5}$ NAAQS and the annual $PM_{2.5}$ NAAQS, there is no case where the annual standard drives the reduction requirements deeper than would the 24-hour standard alone. Thus, emissions reduction requirements for a SIP to address significant contribution and interference with maintenance with respect to the 24-hour $PM_{2.5}$ NAAQS would be based on the SO_2 and NO_X emissions budgets in Table IV.E–1. For such a state, a SIP that addresses the requirements with respect to the 24-hour $PM_{2.5}$ NAAQS would also by definition address the requirements with respect to the annual $PM_{2.5}$ NAAQS.

EPA is taking comment on all aspects of how a state could replace the Transport Rule FIP with a SIP and on what the SIP approval criteria should be.

VIII. Permitting

A. Title V Permitting

EPA's proposed FIPs would not establish any permitting requirements independent of those under Title V of the CAA and the regulations implementing title V, 40 CFR parts 70 and 71.[107] Title V requires that sources meeting certain criteria have permits meeting the requirements specified in Title V and the Title V regulations. For example, for sources required to have Title V permits, such permits must include, among other things, all "applicable requirements," as defined in the Title V regulations (40 CFR 70.2 and 71.2 (definition of "applicable requirement")).

EPA anticipates that, given the nature of the units covered by the proposed FIPs, most of the sources at which they are located would be subject to Title V permitting requirements. For sources subject to Title V, the requirements applicable to them under the proposed FIPs would be "applicable requirements" under Title V and therefore would need to be included in the Title V permits. For example, requirements under the proposed FIPs concerning designated representatives, monitoring, reporting, and recordkeeping, the requirement to hold allowances covering emissions, the assurance provisions, and liability would be "applicable requirements" and necessary to include in the permits.

[107] Part 70 governs approved state Title V programs, and part 71 governs the federal Title V program.

The Title V permits program includes, among other things, provisions for permit applications, permit content, and permit revisions that would address the applicable requirements under the proposed FIPs in a manner that would provide the flexibility necessary to implement a market-based program such as the one that EPA is proposing. For example, the Title V regulations provide that a permit issued under Title V must include, for any "approved * * * emissions trading and other similar programs or processes" applicable to the source, a provision stating that no permit revision is required "for changes that are provided for in the permit." 40 CFR 70.6(a)(8) and 71.6(a)(8). The trading program regulations for the proposed FIPs would include a provision stating that no permit revision is necessary for the allocation, holding, deduction, or transfer of allowances. Consistent with the Title V regulations, this provision would also be included in each Title V permit for a covered source. As a result, allowances could be traded (or allocated, held, or deducted) under the FIPs without a revision of the Title V permit of any of the sources involved.

As a further example of flexibility under Title V, the Title V regulations allow the use of the minor permit modification procedures for permit modifications "involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, to the extent that such minor permit modification procedures are explicitly provided for in an applicable implementation plan or in applicable requirements promulgated by EPA." 40 CFR 70.7(e)(2)(i)(B) and 40 CFR 71.7(e)(1)(i)(B). The trading program regulations for the proposed FIPs would include provisions requiring unit owners and operators to submit monitoring system certification applications (or, for alternative monitoring systems, petitions) to EPA establishing the monitoring and reporting approach to be used by the unit. These applications and petitions are subject to EPA review and approval to ensure consistency in monitoring and reporting among all trading program participants. As provided in the proposed regulations, EPA would only allow use of approaches that would result in emissions data with an appropriate level of precision, reliability, accessibility, and timeliness. The proposed regulations would also include a provision stating that a description of the general approach that each covered unit is required to use for monitoring and reporting emissions (*i.e.*, an approach using a continuous emissions monitoring system, an excepted monitoring system under appendices D and E to part 75, a low mass emissions excepted monitoring methodology under § 75.19, or an alternative monitoring system under subpart E of part 75) could be added to or changed in a Title V permit using minor permit modification procedures, provided that the requirements applicable to the monitoring and reporting addition or change were already incorporated elsewhere in the permit. As a result, minor permit modification procedures could be used to revise a unit's Title V permit to be consistent with any changes in the monitoring and reporting approach allowed for the unit by EPA through the monitoring system certification or petition process in the proposed trading program regulations. However, if the permit did not already incorporate the monitoring and reporting requirements applicable to the change, the permit would also have to be revised to incorporate these requirements, and this change would not qualify as a minor permit modification pursuant to 40 CFR 70.7(e)(2)(i)(B) and 40 CFR 71.7(e)(1)(i)(B).

As new applicable requirements under Title V, the requirements for covered units under the final FIPs would be incorporated into covered sources' existing Title V permits either pursuant to the provisions for reopening for cause (40 CFR 70.7(f) and 40 CFR 71.7(f)) or the permit renewal provisions (40 CFR 70.7(c) and 71.7(c)).[108] For sources newly subject to title V that would also be covered sources under the proposed FIPs, the initial Title V permit issued pursuant to 40 CFR 70.7(a) would include the final FIP requirements. In order to ensure that covered sources' Title V permit provisions concerning the FIPs would reflect, properly and in a manner consistent from permit to permit, the trading program requirements and flexibilities, EPA intends to issue guidance, after promulgation of the final FIPs, to assist permitting authorities. This guidance would include information on permit issuance and permit modification requirements, as well as a permit content template that would identify the applicable requirements under the trading program and thereby ensure that they would be correctly and comprehensively reflected in each permit in a manner that would reduce the need for frequent permit revisions. Use of a permit content template would also reduce the burden on sources in obtaining, on permitting authorities in issuing, and on EPA in reviewing, permits or permit revisions.

[108] A permit is reopened for cause if any new applicable requirements (such as those under a FIP) become applicable to a covered source with a remaining permit term of 3 or more years. If the remaining permit term is less than 3 years, such new applicable requirements will be added to the permit during permit renewal. *See* 40 CFR 70.7(f)(1)(i) and 71.7(f)(1)(i).

B. New Source Review

EPA recognizes that pollution control projects, including pollution control projects constructed to comply with the proposed rule, have the potential to trigger new source review (NSR) permitting.

On December 20, 2005, the EPA agreed to reconsider one specific aspect of the CAIR. In that notice, EPA granted reconsideration and sought comment on the potential impact of a judicial opinion, *New York* v. *EPA*, 413 F.3d 3 (D.C. Cir. 2005). This decision vacated the pollution control project exclusion in EPA's NSR regulations. (The exclusion allowed for certain environmentally beneficial pollution control projects to be excluded from certain NSR requirements.) For this reconsideration, EPA conducted an analysis which showed that the court decision did not impact the CAIR analyses. The EPA believes this analysis, which remains current and relevant for all pollutants except for greenhouse gas (GHG), shows that New Source Review (NSR) requirements would not significantly impact the construction of controls that are installed to comply with the proposed transport rule. Details of this analysis can be found in a Technical Support document which is available on EPA's Web site at: *http://epa.gov/cair/pdfs/0053–2263.pdf.*

Because GHG was not considered by EPA to be a "pollutant", let alone a "regulated pollutant," at the time of CAIR, GHG was not addressed in the previous analysis. GHG requirements related to the component of new source review concerning the Prevention of Significant Deterioration ("PSD") program have recently been addressed in EPA's "Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs," 75 FR 17004 (April 2, 2010), and "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule," 75 FR (June 3, 2010) ("Tailoring Rule"). Generally, as discussed in those actions, once the PSD requirements for GHG take effect on January 2, 2011, major stationary sources will be required to address GHG emissions as part of the PSD program if these sources emit GHG in amounts that equal or exceed the thresholds in the Tailoring Rule. Once the PSD requirements take effect, major sources that undergo a modification, including the addition of pollution control equipment, will trigger PSD requirements for their emissions of GHG if such emissions increase by at least 75,000 tons per year of CO_2 equivalent. EPA believes it is very unlikely that pollution control projects would cause GHG increases that would exceed the 75,000 tons per year threshold.

Consistent with EPA's previous analysis and EPA's conclusions for GHG, EPA does not believe that there are significant impacts from NSR for any pollution control projects resulting from the proposed rule such as low-NO_X burners, SO_2 scrubbers, or SCR. EPA requests comment on this issue.

IX. What benefits are projected for the proposed rule?

In this section, we present the results of EPA's analysis of the benefits of the emissions reductions in this proposal on $PM_{2.5}$ and ozone air quality, public health, welfare, and the environment. These improvements were determined based upon air quality modeling of the 2014 base case and the "State Budgets/ Limited Trading" remedy proposed in this rule, as described in section V, above.

Implementation of this rule will very substantially lower the extent of nonattainment and maintenance problems for the annual and 24-hour $PM_{2.5}$ NAAQS and 8-hour ozone NAAQS in the eastern U.S. (*see* section IX.A, below). The improvements in air quality will annually prevent thousands of premature deaths and other serious health effects (*see* section IX.B, below). We estimate the total monetized annual benefits to be approximately $120 billion to $290 billion or $110 billion to $270 billion in 2014 (at a 3 percent and a 7 percent discount rate, respectively) for the proposed "State Budgets/Limited Trading" remedy. There will be significant benefits that are not quantified. Notably, in 2012 the benefits are actually larger since greater emissions reductions are occurring from the baseline in that timeframe, as indicated in Table V.E–2, above. Because the magnitude of the $PM_{2.5}$ co-benefits is largely driven by the concentration-response function for premature mortality, we examined alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts. Higher and lower co-benefits estimates are plausible, but most of the expert-based estimates fall between these two estimates above.[109] All monetized estimates are stated in 2006 dollars. Also note that the analytic baseline presents a unique situation. EPA has been directed to replace the CAIR; yet the CAIR remains in place and has led to significant emissions reductions in many states.

A key step in the process of developing a 110(a)(2)(D)(i)(I) rule involves analyzing existing (base case) emissions to determine which states significantly contribute to downwind nonattainment and maintenance areas. EPA cannot prejudge at this stage which states will be affected by the rule. For example, a state affected by CAIR may not be affected by the new rule and after the new rule goes into effect, the CAIR requirements will no longer apply. For a state covered by CAIR but not covered by the new rule, the CAIR requirements would not be replaced with new requirements, and therefore an increase in emissions relative to present levels could occur in that state. More fundamentally, the court has made clear that, due to legal flaws, the CAIR rule cannot remain in place and must be replaced. If EPA's base case analysis were to ignore this fact and assume that reductions from CAIR would continue indefinitely, areas that are in attainment solely due to controls required by CAIR would again face nonattainment problems because the existing protection from upwind pollution would not be replaced. For these reasons, EPA cannot assume in its base case analysis, that the reductions required by CAIR will continue to be achieved.

Following this logic, the 2012 base case shows emissions higher than current levels in some states. Because EPA has been directed to replace CAIR, EPA believes that for many states, the absence of the CAIR NO_X program will lead to the status quo of the NO_X Budget Program, which limits ozone-season NO_X emissions and ensures the operation of NO_X controls in those states. Also, without the CAIR SO_2 program, emission requirements in many areas would revert to the comparatively less stringent requirements of the Title IV Acid Rain program. As a result, SO_2 emissions in many states would increase markedly in the 2012 base case relative to the present. Efforts to comply with ARP rules at the least-cost would occur in many cases without the operation of existing scrubbers through use of readily available, inexpensive Title IV allowances. Notably, all known controls that are required under state laws, NSPS, consent decrees, and other enforceable binding commitments through 2014 are accounted for in the base case. It is against this backdrop that the Transport Rule is analyzed and that significant contribution to nonattainment and interference with maintenance must be addressed.

A. The Impacts on $PM_{2.5}$ and Ozone of the Proposed SO_2 and NO_X Strategy

The air quality modeling platform described in section IV.C. was used by EPA to model the impacts of the proposed SO_2 and NO_X emissions reductions on annual average $PM_{2.5}$, 24-hour $PM_{2.5}$, and 8-hour ozone concentrations. In brief, we ran the CAMx model for the meteorological conditions in the year of 2005 for the eastern U.S. modeling domain.[110] Modeling was performed for the 2014 base case and the 2014 "State Budgets/ Limited Trading" scenario to assess the expected effects of the proposed regional strategy on projected $PM_{2.5}$ and ozone design value concentrations and nonattainment and maintenance. The procedures used to project future design values and nonattainment and maintenance are described in section IV.C. The aggregate emissions in 2012 and 2014 for SO_2 and NO_X are provided in Table V.E–2 in section V.E. The emissions by state are provided in Tables V.E–5 through V.E–7 in section V.E, and also in the Air Quality Modeling TSD.

The projected 2014 concentrations of annual $PM_{2.5}$, daily $PM_{2.5}$, and ozone at each monitoring site in the East for which projections were made are provided in the AQMTSD. The number of nonattainment and/or maintenance sites in the East for the 2012 base case, 2014 base case, and 2014 remedy for annual $PM_{2.5}$, daily $PM_{2.5}$, and ozone are provided in Table IX–1.[111] The average and peak reductions in annual $PM_{2.5}$, daily $PM_{2.5}$, and ozone predicted at 2012 nonattainment and/or maintenance sites due to the emissions reductions

[109] Roman *et al.,* 2008. Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S. Environ. Sci. Technol., 42, 7, 2268–2274.

[110] As described in the AQMTSD, the eastern U.S. was modeled at a horizontal resolution of 12 x 12 km. The remainder of the U.S. was modeled at a resolution of 36 x 36 km.

[111] To provide a point of reference, Table IX–1 also includes the number of nonattainment and/ maintenance sites based on ambient design values for the period 2003 through 2007.

between 2012 and the 2014 remedy are provided in Table IX–2.

TABLE IX–1—PROJECTED REDUCTION IN NONATTAINMENT AND/OR MAINTENANCE PROBLEMS FOR $PM_{2.5}$ AND OZONE IN THE EASTERN U.S.

	Ambient (2003–2007)	2012 base case	2014 base case	2014 proposed remedy	Percent reduction: 2012 base case vs. 2014 remedy (percent)	Percent reduction: 2014 base case vs. 2014 remedy (percent)
Annual $PM_{2.5}$ Nonattainment Sites [112]	102	32	15	1	97	93
Annual $PM_{2.5}$ Maintenance-Only Sites	21	16	7	1	94	86
Daily $PM_{2.5}$ Nonattainment Sites	151	92	54	17	82	69
Daily $PM_{2.5}$ Maintenance-Only Sites	48	38	28	11	71	61
Ozone Nonattainment Sites	103	11	7	7	36	0
Ozone Maintenance-Only Sites	67	16	6	5	69	17

TABLE IX–2—AVERAGE AND PEAK REDUCTION IN ANNUAL $PM_{2.5}$, DAILY $PM_{2.5}$, AND OZONE FOR SITES THAT ARE PROJECTED TO HAVE NONATTAINMENT AND/OR MAINTENANCE PROBLEMS IN THE 2012 BASE CASE

	Average reduction: 2012 base case to 2014 remedy	Peak reduction: 2012 base case to 2014 remedy
Annual $PM_{2.5}$ Nonattainment Sites	2.8 µg/m³	3.9 µg/m³
Annual $PM_{2.5}$ Maintenance-Only Sites	2.6 µg/m³	4.2 µg/m³
Daily $PM_{2.5}$ Nonattainment Sites	5.8 µg/m³	15.3 µg/m³
Daily $PM_{2.5}$ Maintenance-Only Sites	5.1 µg/m³	13.5 µg/m³
Ozone Nonattainment Sites	1.9 ppb	3.9 ppb
Ozone Maintenance-Only Sites	2.3 ppb	4.2 ppb

The information in Table IX–1 shows that there will be significant reductions in the extent of nonattainment and maintenance problems for annual $PM_{2.5}$, daily $PM_{2.5}$, and ozone between 2012 and 2014 as a result of the emissions budgets in this proposal coupled with emissions reductions during this time period from other existing control programs. Specifically, the results of the air quality modeling indicate that all but 1 site is projected to be in attainment and only 1 site is projected to have a maintenance problem for annual $PM_{2.5}$ in 2014 with the emissions reductions expected from this proposal. As indicated in Table IX–2, the average reduction in annual $PM_{2.5}$ across the 32 2012 nonattainment sites is 1.9 µg/m³ and the peak reduction at an individual nonattainment site is 3.2 µg/m³. Comparable reductions are projected at annual $PM_{2.5}$ maintenance-only sites.

For 24-hour $PM_{2.5}$, we project that the number of nonattainment sites will be reduced by 82 percent and the number of maintenance-only sites by 71 percent in 2014 compared to the 2012 base case. The average reduction in 24-hour $PM_{2.5}$ across the 92 2012 nonattainment sites is 5.8 µg/m³ and the peak reduction at an individual nonattainment site is 15.3 µg/m³. Comparable reductions are projected at 24-hour $PM_{2.5}$ maintenance-only sites.

The emissions reductions in this proposal will result in considerable progress toward attainment and maintenance at the 28 sites that remain as nonattainment and/or maintenance for the 24-hour $PM_{2.5}$ standard. On average for these 28 sites, the predicted amount of $PM_{2.5}$ reduction in 2014 is more than half of what is needed for these sites to attain and/or maintain the 24-hour standard.

Thus, the SO_2 and NO_X emissions reductions which will result from today's proposal will greatly reduce the extent of $PM_{2.5}$ nonattainment and maintenance problems by 2014 and beyond. As described previously, these emissions reductions are expected to substantially reduce the number of $PM_{2.5}$ nonattainment and/or maintenance sites in the East and make attainment easier for those counties that remain nonattainment by substantially lowering $PM_{2.5}$ concentrations in residual nonattainment sites. The emissions reductions will also help those locations that may have maintenance problems.

Based on the 2012 base air quality modeling for ozone, 27 sites in the East are projected to be nonattainment or have problems maintaining the 1997 ozone standard. The initial phase of summer NO_X reductions in today's proposal are projected to lower 8-hour ozone concentration by 2.8 ppb, on average by 2014, at monitoring sites projected to be nonattainment and/or have maintenance problems in the 2012 base case. We expect that the number of nonattainment sites will be reduced by 36 percent and the number of maintenance-only sites by 69 percent in 2014 compared to the 2012 base case. For the 12 sites expected to have residual nonattainment/maintenance problems in 2014, the predicted ozone reductions provide nearly 10 percent of the amount needed for these sites to attain and/or maintain the ozone standard. Thus, our modeling indicates that by 2014 the initial phase of summer NO_X emissions reductions in this proposal will lower ozone concentrations in the East and help bring areas closer to attainment for the 8-hour ozone NAAQS.

[112] "Nonattainment" is used to denote sites that are projected to have both nonattainment and maintenance problems.

B. Human Health Benefit Analysis

To estimate the human health benefits of the proposed Transport Rule, we used the BenMAP model to quantify the changes in $PM_{2.5}$ and ozone-related health impacts and monetized benefits based on changes in air quality. We provide such estimates for the proposed remedy option. Notably, EPA expects that in 2014 the other two alternatives that the Agency considered have the same general level of benefits that will result from their implementation. The results of the analysis for the alternate SO_2 reduction scenarios are found in the RIA. For context, it is important to note that the magnitude of the $PM_{2.5}$ benefits is largely driven by the concentration response function for premature mortality. Experts have advised EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$ concentrations and premature mortality. For this proposed rule we cite two key empirical studies, one based on the American Cancer Society cohort study [113] and the other based on the extended Six Cities cohort study.[114]

Table IX–3 presents the primary estimates of reduced incidence of $PM_{2.5}$ and ozone-related health effects in 2014 for the proposed and alternative remedies. In 2014, we estimate that PM-related annual benefits of the proposed remedy include approximately 14,000 to 36,000 fewer premature mortalities, 9,200 fewer cases of chronic bronchitis, 22,000 fewer non-fatal heart attacks, 11,000 fewer hospitalizations (for respiratory and cardiovascular disease combined), 10 million fewer days of restricted activity due to respiratory illness and approximately 1.8 million fewer work-loss days. We also estimate substantial health improvements for children from fewer cases of upper and lower respiratory illness, acute bronchitis, and asthma attacks. As mentioned earlier, the reduced incidences of various effects would be greater in 2012 due to the larger emissions reductions that occur from the baseline. The lower reductions in emissions in 2014 result from further SO_2 controls in the proposed remedy because the baseline has much greater controls resulting from state actions and consent decrees.

Ozone health-related benefits are expected to occur during the summer ozone season (usually ranging from May to September in the eastern U.S.). Based upon modeling for 2014, annual ozone related health benefits are expected to include between 50 and 230 fewer premature mortalities, 690 fewer hospital admissions for respiratory illnesses, 230 fewer emergency room admissions for asthma, 300,000 fewer days with restricted activity levels, and 110,000 fewer days where children are absent from school due to illnesses. When adding the PM and ozone-related mortalities together, we find that the proposed Transport Rule will yield between 14,000 and 36,000 fewer premature mortalities. The following references are used in providing our estimates of ozone health-related benefits:

Bell, M.L., *et al.* 2004. Ozone and short-term mortality in 95 U.S. urban communities, 1987–2000. Journal of the American Medical Association. 292 (19): p. 2372–8.

Laden, F., J. Schwartz, F.E. Speizer, and D.W. Dockery. 2006. Reduction in Fine Particulate Air Pollution and Mortality. American Journal of Respiratory and Critical Care Medicine 173:667–672. Estimating the Public Health Benefits of Proposed Air Pollution Regulations. Washington, DC: The National Academies Press.

Levy JI, Baxter LK, Schwartz J. 2009. Uncertainty and variability in health-related damages from coal-fired power plants in the United States. Risk Anal. doi: 10.1111/j.1539–6924.2009.01227.x [Online 9 Apr 2009]

Pope, C.A., III, R.T. Burnett, M.J. Thun, E.E. Calle, D. Krewski, K. Ito, and G.D. Thurston. 2002. Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution. Journal of the American Medical Association 287:1132–1141.

TABLE IX–3—ESTIMATED ANNUAL REDUCTIONS IN INCIDENCE OF HEALTH EFFECTS [A]

Health effect	Proposed remedy
PM-Related endpoints	
Premature Mortality	
Pope *et al.* (2002) (age >30)	14,000 (4,000–25,000)
Laden *et al.* (2006) (age >25)	36,000 (17,000–56,000)
Infant (< 1 year)	59 (−66–180)
Chronic Bronchitis	9,200 (320–18,000)
Non-fatal heart attacks (age > 18)	22,000 (5,800–39,000)
Hospital admissions—respiratory (all ages)	3,500 (1,400–5,500)
Hospital admissions—cardiovascular (age > 18)	7,500 (5,200–8,900)
Emergency room visits for asthma (age < 18)	14,000 (7,200–21,000)
Acute bronchitis (age 8–12)	21,000 (−4,800–46,000)
Lower respiratory symptoms (age 7–14)	250,000 (98,000–400,000)
Upper respiratory symptoms (asthmatics age 9–18)	190,000 (36,000–350,000)
Asthma exacerbation (asthmatics 6–18)	240,000 (8,300–800,000)
Lost work days (ages 18–65)	1,800,000 (1,500,000–2,000,000)
Minor restricted-activity days (ages 18–65)	10,000,000 (8,600,000–12,000,000)
Ozone-related endpoints	
Premature mortality	
Bell *et al.* (2004) (all ages)	50 (17–84)
Levy *et al.* (2005) (all ages)	230 (160–300)
Hospital admissions—respiratory causes (ages > 65)	390 (−18–740)
Hospital admissions—respiratory causes (ages < 2)	300 (130–460)
Emergency room visits for asthma (all ages)	230 (−30–730)
Minor restricted-activity days (ages 18–65)	300,000 (130,000–480,000)

[113] Pope *et al.*, 2002. "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." *Journal of the American Medical Association.* 287:1132–1141.

[114] Laden *et al.*, 2006. "Reduction in Fine Particulate Air Pollution and Mortality." *American Journal of Respiratory and Critical Care Medicine.* 173:667–672.

TABLE IX–3—ESTIMATED ANNUAL REDUCTIONS IN INCIDENCE OF HEALTH EFFECTS [A]—Continued

Health effect	Proposed remedy
School absence days	110,000 (38,000–160,000)

[A] Values rounded to two significant figures. Benefits from reducing other criteria pollutants and hazardous air pollutants and ecosystem effects are not included here.

C. Quantified and Monetized Visibility Benefits

Only a subset of the expected visibility benefits—those for Class I areas—are included in the monetary benefits estimates we project for this rule. We anticipate improvement in visibility in residential areas where people live, work and recreate within the Transport Rule region for which we are currently unable to monetize benefits. For the Class I areas we estimate annual benefits of $3.4 billion beginning in 2014 for visibility improvements. Methodological limitations prevented us from quantifying the visibility benefits of the alternate remedies. The value of visibility benefits in areas where we were unable to monetize benefits could also be substantial.

D. Benefits of Reducing GHG Emissions

When fully implemented in 2014, the proposed Transport Rule would reduce emissions of CO_2 from electrical generating units by about 15 million metric tons annually. Using a "social cost of carbon" (SCC) estimate that accounts for the marginal dollar value (*i.e.*, cost) of climate-related damages resulting from CO_2 emissions, previous analyses including the RIA for the Final Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emissions Standards and Corporate Average Fuel Efficiency Standards have found the total benefit of CO_2 reductions is substantial. The monetary value of these avoided damages also grows over time. Readers interested in learning more about the calculation of the SCC metric should refer to the SCC TSD, *Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* [Docket No. EPA–HQ–OAR–2009–0472].

E. Total Monetized Benefits

Table IX–4 presents the estimated monetary value of reductions in the incidence of health and welfare effects. These estimates account for increases in the value of risk reduction over time. As the table indicates, total benefits are driven primarily by the reduction in premature fatalities each year, which account for over 90 percent of total benefits.

Table IX–5 presents the total monetized net benefits for 2014. A listing of the benefit categories that could not be quantified or monetized in our benefit estimates are provided in Table IX–6.

TABLE IX–4—ESTIMATED ANNUAL MONETARY VALUE OF REDUCTIONS IN INCIDENCE OF HEALTH AND WELFARE EFFECTS

(Billions Of 2006$) [A]

Health effect	Pollutant	Proposed remedy
Premature mortality (Pope *et al.* 2002 PM mortality and Bell *et al.* 2004 ozone mortality estimates)		
3% discount rate	$PM_{2.5}$ & O_3	$110 ($8.8–$340)
7% discount rate	$PM_{2.5}$ & O_3	$100 ($7.9–$300)
Premature mortality (Laden *et al.* 2006 PM mortality and Levy *et al.* 2005 ozone mortality estimates)		
3% discount rate	$PM_{2.5}$ & O_3	$280 ($25–$820)
7% discount rate	$PM_{2.5}$ & O_3	$260 ($22–$310)
Chronic bronchitis	$PM_{2.5}$	$4.3 $0.2–$20)
Non-fatal heart attacks.		
3% discount rate	$PM_{2.5}$	$2.5 ($0.4–$6)
7% discount rate	$PM_{2.5}$	$2.4 ($0.4–$5.9)
Hospital admissions—respiratory	$PM_{2.5}$ & O_3	$0.06 ($0.03–$0.1)
Hospital admissions—cardiovascular	$PM_{2.5}$	$0.2 ($0.1–$0.3)
Emergency room visits for asthma	$PM_{2.5}$ & O_3	$0.005 ($0.002–$0.008)
Acute bronchitis	$PM_{2.5}$	$0.009 (−$0.0004–$0.03)
Lower respiratory symptoms	$PM_{2.5}$	$0.005 ($0.002–$0.009)
Upper respiratory symptoms	$PM_{2.5}$	$0.006 ($0.001–$0.014)
Asthma exacerbation	$PM_{2.5}$	$0.012 ($0.001–$0.046)
Lost work days	$PM_{2.5}$	$0.2 ($0.19–$0.24)
School loss days		$0.01 ($0.004–$0.013)
Minor restricted-activity days	$PM_{2.5}$ & O_3	$0.64 ($0.34–$0.97)
Recreational visibility, Class I areas	$PM_{2.5}$	$3.6
Total benefits based on Pope *et al.* 2002 PM mortality and Bell *et al.* 2004 ozone mortality estimates		
3% discount rate	$PM_{2.5}$ & O_3	$120 ($10–$360)
7% discount rate	$PM_{2.5}$ & O_3	$110 ($9–$330)
Total benefits based on Laden *et al.* 2006 PM mortality and Levy *et al.* 2005 ozone mortality estimates		
3% discount rate	$PM_{2.5}$ & O_3	$290 ($26–$840)
7% discount rate	$PM_{2.5}$ & O_3	$270 ($24–$760)

[A] Estimates rounded to two significant figures.

E. How do the benefits compare to the costs of this proposed rule?

The estimated annual private costs to implement the emission reduction requirements of the proposed rule for the Transport Rule region are $3.7 billion in 2012 and $2.8 billion in 2014 (2006$) for the proposed remedy option, $4.2 billion in 2012 and $2.7 billion in 2014 for the State Budgets/Intrastate Trading remedy option, and $4.3 billion in 2012 and $3.4 billion in 2014 for the direct control remedy option. These costs are the annual incremental electric generation production costs that are expected to occur with the Transport Rule. The EPA uses these costs as compliance cost estimates in developing cost-effectiveness estimates.

In estimating the net benefits of regulation, the appropriate cost measure is "social costs." Social costs represent the welfare costs of the rule to society. These costs do not consider transfer payments (such as taxes) that are simply redistributions of wealth. The social costs of this rule (thus reflecting the proposed remedy option) are estimated to be approximately $2.0 billion in 2014 assuming a 3 percent discount rate. These costs become $2.2 billion in 2014, if one assumes a 7 percent discount rate. Thus, the net benefit (social benefits minus social costs) as will be shown in Table IX–5 for the proposed remedy option is approximately $120 to 292 billion or $109 to 264 billion (3 percent and 7 percent discount rates) in 2014. Implementation of the rule is expected to provide society with a substantial net gain in social welfare based on economic efficiency criteria.

The annualized regional cost of the proposed rule, as quantified here, is EPA's best assessment of the cost of implementing the proposed option. These costs are generated from rigorous economic modeling of changes in the power sector expected from the proposed rule. This type of analysis using IPM has undergone peer review and been upheld in federal courts. The direct cost includes, but is not limited to, capital investments in pollution controls, operating expenses of the pollution controls, investments in new generating sources, and additional fuel expenditures. The EPA believes that these costs reflect, as closely as possible, the additional costs of the proposed option to industry. The relatively small cost associated with monitoring emissions, reporting, and recordkeeping for affected sources is not included in these annualized cost estimates, but EPA has done a separate analysis and estimated the cost to less than $28 million (see section XII.B., Paperwork Reduction Act). However, there may exist certain costs that EPA has not quantified in these estimates. These costs may include costs of transitioning to this rule, such as the costs associated with the retirement of smaller or less efficient EGUs, employment shifts as workers are retrained at the same company or re-employed elsewhere in the economy, and certain relatively small permitting costs associated with Title V that new program entrants face.

An optimization model was employed that assumes cost minimization. Costs may be understated if the regulated community chooses not to minimize its compliance costs in the same manner to comply with the rules. Although EPA has not quantified these costs, the Agency believes that they are small compared to the quantified costs of the program on the power sector. However, EPA's experience and results of independent evaluation suggests that costs are likely to be lower by some degree (*see* RIA for details). The annualized cost estimates presented are the best and most accurate based upon available information. In a separate analysis, EPA estimates the indirect costs and impacts of higher electricity prices on the entire economy. These impacts are summarized in section X of this preamble and in the RIA for this proposed rule.

TABLE IX–5—SUMMARY OF ANNUAL BENEFITS, COSTS, AND NET BENEFITS OF THE TRANSPORT RULE IN 2014

[Billions of 2006 dollars]

Description	Proposed remedy
Social costs:	
3 percent discount rate	$2.0.
7 percent discount rate	$2.2.
Social benefits:	
3 percent discount rate	$122 to 294 + B.
7 percent discount rate	$111 to 266 + B.
Health-related benefits:	
3 percent discount rate	$118 to 290.
7 percent discount rate	$107 to 262.
Visibility benefits:	
3 percent discount rate	$3.6.
7 percent discount rate	$3.6.
Annual net benefits (benefits-costs)	
3 percent discount rate	$120 to 292.
7 percent discount rate	$109 to 264.

[a] All estimates are rounded to three significant digits and represent annualized benefits and costs anticipated for 2014. Estimates relate to the complete Transport Rule program.

[b] Note that costs are the annual total costs of reducing pollutants including NO_X and SO_2 in the Transport Rule region.

[c] As this table indicates, total benefits are driven primarily by $PM_{2.5}$-related health benefits. The reduction in premature fatalities each year accounts for over 90 percent of total monetized benefits 2014. Benefits in this table are nationwide (with the exception of visibility) and are associated with NO_X and SO_2 reductions for the EGU source category. Ozone benefits represent benefits in the eastern United States. Visibility benefits represent benefits in Class I areas in the southeastern United States.

[d] Not all possible benefits or disbenefits are quantified and monetized in this analysis. Potential benefit categories that have not been quantified and monetized are listed in Table IX–6. We represent the value of unquantified benefits and disbenefits with a "B."

[e] Valuation assumes discounting over the SAB-recommended 20 year segmented lag structure described in chapter 4 of the Regulatory Impact Analysis for the Clean Air Interstate Rule (March 2005). Results reflect 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (U.S. EPA, 2000 and OMB, 2003).174

[f] Net benefits are rounded to the nearest $1 billion. Columnar totals may not sum due to rounding.

Every benefit-cost analysis examining the potential effects of a change in environmental protection requirements is limited to some extent by data gaps, limitations in model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Gaps in the scientific literature often result in the inability to estimate quantitative changes in health and environmental effects. Gaps in the economics literature often result in the inability to assign economic values even to those health and environmental outcomes that can be quantified. While uncertainties in the underlying scientific and economics literatures (that may result in overestimation or underestimation of benefits) are discussed in detail in the economic analyses and its supporting documents and references, the key uncertainties which have a bearing on the results of the benefit-cost analysis of this rule include the following:

- EPA's inability to quantify potentially significant benefit categories;
- Uncertainties in population growth and baseline incidence rates;
- Uncertainties in projection of emissions inventories and air quality into the future;
- Uncertainty in the estimated relationships of health and welfare effects to changes in pollutant concentrations including the shape of the C–R function, the size of the effect estimates, and the relative toxicity of the many components of the PM mixture;
- Uncertainties in exposure estimation; and
- Uncertainties associated with the effect of potential future actions to limit emissions.

Despite these uncertainties, we believe the benefit-cost analysis provides a reasonable indication of the expected economic benefits of the rulemaking in future years under a set of reasonable assumptions. This approach calculates a mean value across VSL estimates derived from 26 labor market and contingent valuation studies published between 1974 and 1991. The mean VSL across these studies is $6.3 million (2000$).[115] The benefits estimates generated for this rule are subject to a number of assumptions and uncertainties, which are discussed throughout the RIA document.

As Table IX–4 indicates, total benefits are driven primarily by the reduction in premature mortalities each year. Some key assumptions underlying the primary estimate for the premature mortality category include the following:

(1) EPA assumes inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a daily basis. Plausible biological mechanisms for this effect have been hypothesized for the endpoints included in the primary analysis and the weight of the available epidemiological evidence supports an assumption of causality.

(2) EPA assumes all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because the proportion of certain components in the PM mixture produced via precursors emitted from EGUs may differ significantly from direct PM released from automotive engines and other industrial sources, but no clear scientific grounds exist for supporting differential effects estimates by particle type.

(3) We assume that the health impact function for fine particles is linear down to the lowest air quality levels modeled in this analysis. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of $PM_{2.5}$, including both regions that are in attainment with fine particle standard and those that do not meet the standard down to the lowest modeled concentrations.

The EPA recognizes the difficulties, assumptions, and inherent uncertainties in the overall enterprise. The analyses upon which the Transport Rule is based were selected from the peer-reviewed scientific literature. We used up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.

There are a number of health and environmental effects that we were unable to quantify or monetize. A complete benefit-cost analysis of the Transport Rule requires consideration of all benefits and costs expected to result from the rule, not just those benefits and costs which could be expressed here in dollar terms. A listing of the benefit categories that were not quantified or monetized in our estimate are provided in Table IX–6.

F. What are the unquantified and unmonetized benefits of the Transport Rule emissions reductions?

Important benefits beyond the human health and welfare benefits resulting from reductions in ambient levels of $PM_{2.5}$ and ozone in the eastern United States are expected to occur from this rule. These other benefits occur both directly from NO_X and SO_2 emissions reductions. These benefits are listed in Table IX–6. Some of the more important examples include: Reductions in NO_X and SO_2 emissions required by the Transport Rule will reduce acidification and, in the case of NO_X, eutrophication of water bodies. Reduced nitrate contamination of drinking water is another possible benefit of the rule. This proposed rule will also reduce acid and particulate deposition that causes damages to cultural monuments, as well as, soiling and other materials damage. To illustrate the important nature of benefit categories we are currently unable to monetize, we discuss four categories of public welfare and environmental impacts related to reductions in emissions required by the Transport Rule: Reduced acid deposition, reduced eutrophication of estuaries, and reduced vegetation impairment from ozone.

1. What are the benefits of reduced deposition of sulfur and nitrogen to aquatic, forest, and coastal ecosystems?

Atmospheric deposition of sulfur and nitrogen, often referred to as acid rain, occurs when emissions of SO_2 and NO_X react in the atmosphere (with water, oxygen, and oxidants) to form various acidic compounds. These acidic compounds fall to earth in either a wet form (rain, snow, and fog) or a dry form (gases and particles). Prevailing winds can transport acidic compounds hundreds of miles, across state borders. Together these emissions are deposited onto terrestrial and aquatic ecosystems across the U.S., contributing to the problems of acidification, nutrient enrichment, and methylmercury production. In addition, NO_X is a precursor to ozone, which can impair vegetation.

a. Acid Deposition and Acidification of Lakes and Streams

The extent of adverse effects of acid deposition on freshwater and forest ecosystems depends largely upon the ecosystem's ability to neutralize the acid. The neutralizing ability [key indicator is termed Acid Neutralizing Capacity (ANC)] depends largely on the watershed's physical characteristics, such as geology, soils, and size. Acidic conditions occur more frequently during rainfall and snowmelt that cause high flows of water and less commonly during low-flow conditions, except where chronic acidity conditions are severe. Biological effects are primarily attributable to a combination of low pH and high inorganic aluminum

[115] In this analysis, we adjust the VSL to account for a different currency year (2006$) and to account for income growth to 2014. After applying these adjustments to the $6.3 million value, the VSL is $8.5 million.

concentrations. Biological effects of episodes include reduced fish condition factor, changes in species composition and declines in aquatic species richness across multiple taxa, ecosystems and regions, as well as fish mortality. Waters that are sensitive to acidification tend to be located in small watersheds that have few alkaline minerals and shallow soils. Conversely, watersheds that contain alkaline minerals, such as limestone, tend to have waters with a high ANC. Areas especially sensitive to acidification include portions of the Northeast (particularly, the Adirondack and Catskill Mountains, portions of New England, and streams in the mid-Appalachian highlands) and southeastern streams. This regulatory action will decrease acid deposition in the transport region and is likely to have positive effects on the health and productivity of aquatic ecosystems in the region.

b. Acid Deposition and Forest Ecosystem Impacts

Acidifying deposition has altered major biogeochemical processes in the U.S. by increasing the nitrogen and sulfur content of soils, accelerating nitrate and sulfate leaching from soil to drainage waters, depleting base cations (especially calcium and magnesium) from soils, and increasing the mobility of aluminum. Inorganic aluminum is toxic to some tree roots. Plants affected by high levels of aluminum from the soil often have reduced root growth, which restricts the ability of the plant to take up water and nutrients, especially calcium (U.S. EPA, 2008f). These direct effects can, in turn, influence the response of these plants to climatic stresses such as droughts and cold temperatures. They can also influence the sensitivity of plants to other stresses, including insect pests and disease (Joslin *et al.*, 1992), leading to increased mortality of canopy trees.

Both coniferous and deciduous forests throughout the eastern U.S. are experiencing gradual losses of base cation nutrients from the soil due to accelerated leaching for acidifying deposition. This change in nutrient availability may reduce the quality of forest nutrition over the long term. Evidence suggests that red spruce and sugar maple in some areas in the eastern U.S. have experienced declining health because of this deposition. For red spruce (*Picea rubens*), dieback or decline has been observed across high elevation landscapes of the northeastern U.S., and to a lesser extent, the southeastern U.S., and acidifying deposition has been implicated as a causal factor (DeHayes *et al.*, 1999).

This regulatory action will decrease acid deposition in the transport region and is likely to have positive effects on the health and productivity of forest systems in the region.

c. Coastal Ecosystems

Since 1990, a large amount of research has been conducted on the impact of nitrogen deposition to coastal waters. Nitrogen is often the limiting nutrient in coastal ecosystems. Increasing the levels of nitrogen in coastal waters can cause significant changes to those ecosystems. In recent decades, human activities have accelerated nitrogen nutrient inputs, causing excessive growth of algae and leading to degraded water quality and associated impairments of estuarine and coastal resources.

Atmospheric deposition of nitrogen is a significant source of nitrogen to many estuaries. The amount of nitrogen entering estuaries due to atmospheric deposition varies widely, depending on the size and location of the estuarine watershed and other sources of nitrogen in the watershed. A recent assessment of 141 estuaries nationwide by the National Oceanic and Atmospheric Administration (NOAA) concluded that 19 estuaries (13 percent) suffered from moderately high or high levels of eutrophication due to excessive inputs of both N and phosphorus, and a majority of these estuaries are located in the coastal area from North Carolina to Massachusetts (NOAA, 2007). For estuaries in the Mid-Atlantic region, the contribution of atmospheric distribution to total N loads is estimated to range between 10 percent and 58 percent (Valigura *et al.*, 2001).

Eutrophication in estuaries is associated with a range of adverse ecological effects. The conceptual framework developed by NOAA emphasizes four main types of eutrophication effects—low dissolved oxygen (DO), harmful algal blooms (HABs), loss of submerged aquatic vegetation (SAV), and low water clarity. Low DO disrupts aquatic habitats, causing stress to fish and shellfish, which, in the short-term, can lead to episodic fish kills and, in the long-term, can damage overall growth in fish and shellfish populations. Low DO also degrades the aesthetic qualities of surface water. In addition to often being toxic to fish and shellfish, and leading to fish kills and aesthetic impairments of estuaries, HABs can, in some instances, also be harmful to human health. SAV provides critical habitat for many aquatic species in estuaries and, in some instances, can also protect shorelines by reducing wave strength; therefore, declines in SAV due to nutrient enrichment are an important source of concern. Low water clarity is the result of accumulations of both algae and sediments in estuarine waters. In addition to contributing to declines in SAV, high levels of turbidity also degrade the aesthetic qualities of the estuarine environment.

Estuaries in the eastern United States are an important source of food production, in particular fish and shellfish production. The estuaries are capable of supporting large stocks of resident commercial species, and they serve as the breeding grounds and interim habitat for several migratory species.

This rule is anticipated to reduce nitrogen deposition in the Transport Rule region. Thus, reductions in the levels of nitrogen deposition will have a positive impact upon current eutrophic conditions in estuaries and coastal areas in the region.

d. Mercury Methylation and Deposition

Mercury is a highly neurotoxic contaminant that enters the food web as a methylated compound, methylmercury (U.S. EPA, 2008d). The contaminant is concentrated in higher trophic levels, including fish eaten by humans. Experimental evidence has established that only inconsequential amounts of methylmercury can be produced in the absence of sulfate. Current evidence indicates that in watersheds where mercury is present, increased SO_X deposition very likely results in methylmercury accumulation in fish (Drevnick *et al.*, 2007; Munthe *et al.,* 2007). The SO_2 ISA (U.S. EPA, 2008) concluded that evidence is sufficient to infer a casual relationship between sulfur deposition and increased mercury methylation in wetlands and aquatic environments.

2. Ozone Vegetation Effects

Ozone causes discernible injury to a wide array of vegetation (U.S. EPA, 2006; Fox and Mickler, 1996). In terms of forest productivity and ecosystem diversity, ozone may be the pollutant with the greatest potential for regional-scale forest impacts (U.S. EPA, 2006). Studies have demonstrated repeatedly that ozone concentrations commonly observed in polluted areas can have substantial impacts on plant function (De Steiguer *et al.*, 1990; Pye, 1988).

Assessing the impact of ground-level ozone on forests in the eastern United States involves understanding the risks to sensitive tree species from ambient ozone concentrations and accounting for the prevalence of those species within the forest. As a way to quantify the risks to particular plants from ground-level ozone, scientists have developed ozone-exposure/tree-response functions by exposing tree seedlings to different ozone levels and measuring reductions in growth as "biomass loss." Typically, seedlings are used because they are easy to manipulate and measure their growth loss from ozone pollution. The mechanisms of susceptibility to ozone within the leaves of seedlings and mature trees are identical, and the decreases predicted using the seedlings should be related to the decrease in overall plant fitness for mature trees, but the magnitude of the effect may be higher or lower depending on the tree species (Chappelka and Samuelson, 1998). In areas where certain ozone-sensitive species dominate the forest community, the biomass loss from ozone can be significant. Significant biomass loss can be defined as a more than 2 percent annual biomass loss, which would cause long-term ecological harm as the short-term negative effects on seedlings compound to affect long-term forest health (Heck, 1997).

Urban ornamentals are an additional vegetation category likely to experience some degree of negative effects associated with exposure to ambient ozone levels. Because ozone causes visible foliar injury, the aesthetic value of ornamentals (such as petunia, geranium, and poinsettia) in urban landscapes would be reduced (U.S. EPA, 2007). Sensitive ornamental species would require more frequent replacement and/or increased maintenance (fertilizer or pesticide application) to maintain the desired appearance because of exposure to ambient ozone (U.S. EPA, 2007). In addition, many businesses rely on healthy-looking vegetation for their livelihoods (e.g., horticulturalists, landscapers, Christmas tree growers, farmers of leafy crops, etc.) and a variety of ornamental species have been listed as sensitive to ozone (Abt Associates, 1995).

3. Other Health or Welfare Disbenefits of the Transport Rule That Have Not Been Quantified

In contrast to the additional benefits of the proposed rule discussed above, it is also possible that this rule will result in disbenefits in some areas of the region. Current levels of nitrogen deposition in these areas may provide passive fertilization for forest and terrestrial ecosystems where nutrients are a limiting factor and for some croplands. The effects of ozone and PM on radiative transfer in the atmosphere can also lead to effects of uncertain magnitude and direction on the penetration of ultraviolet light and climate. Ground level ozone makes up a small percentage of total atmospheric ozone (including the stratospheric layer) that attenuates penetration of ultraviolet-b (UVb) radiation to the ground. The EPA's past evaluation of the information indicates that potential disbenefits would be small, variable, and with too many uncertainties to attempt quantification of relatively small changes in average ozone levels over the course of a year (EPA, 2005a). The EPA's most recent provisional assessment of the currently available information indicates that potential but unquantifiable benefits may also arise from ozone-related attenuation of UVb radiation (EPA, 2005b). Sulfate and nitrate particles also scatter UVb, which can decrease exposure of horizontal surfaces to UVb, but increase exposure of vertical surfaces. In this case as well, both the magnitude and direction of the effect of reductions in sulfate and nitrate particles are too uncertain to quantify (EPA, 2004). Ozone is a greenhouse gas, and sulfates and nitrates can reduce the amount of solar radiation reaching the earth, but EPA believes that we are unable to quantify any net climate-related disbenefit or benefit associated with the combined ozone and PM reductions in this rule.

Additionally, from analyses of the benefits of the Acid Rain Program, EPA has seen that substantial health and environmental benefits that are likely to occur for Canadians because 80 percent of the Canadian population lives within 40 miles of the US-Canada border.

TABLE IX–6—UNQUANTIFIED AND NON-MONETIZED EFFECTS OF THE TRANSPORT RULE

Pollutant/effect	Endpoint
PM: health [a]	Low birth weight. Pulmonary function. Chronic respiratory diseases other than chronic bronchitis. Non-asthma respiratory emergency room visits. UVb exposure (+/−) [c].
PM: welfare	Household soiling. Visibility in residential and non-class I areas. UVb exposure (+/−) [c]. Global climate impacts [c].
Ozone: health	Chronic respiratory damage. Premature aging of the lungs. Non-asthma respiratory emergency room visits. Increased exposure to UVb (+/−) [c].
Ozone: welfare	Yields for: —Commercial forests. —Fruits and vegetables, and —Other commercial and noncommercial crops. Damage to urban ornamental plants. Recreational demand from damaged forest aesthetics. Ecosystem functions. Increased exposure to UVb (+/−) [c].
NO_2: health	Respiratory hospital admissions. Respiratory emergency department visits. Asthma exacerbation. Acute respiratory symptoms. Premature mortality. Pulmonary function.
NO_2: welfare	Commercial fishing and forestry from acidic deposition. Commercial fishing, agriculture and forestry from nutrient deposition. Recreation in terrestrial and estuarine ecosystems from nutrient deposition.

TABLE IX–6—UNQUANTIFIED AND NON-MONETIZED EFFECTS OF THE TRANSPORT RULE—Continued

Pollutant/effect	Endpoint
	Other ecosystem services and existence values for currently healthy ecosystems.
SO_2: health	Respiratory hospital admissions.
	Asthma emergency room visits.
	Asthma exacerbation.
	Acute respiratory symptoms.
	Premature mortality.
	Pulmonary function.
SO_2: welfare	Commercial fishing and forestry from acidic deposition.
	Recreation in terrestrial and aquatic ecosystems from acid deposition.
	Increased mercury methylation.

[a] In addition to primary economic endpoints, there are a number of biological responses that have been associated with PM health effects including morphological changes and altered host defense mechanisms. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[b] Cohort estimates are designed to examine the effects of long term exposures to ambient pollution, but relative risk estimates may also incorporate some effects due to shorter term exposures (*see* Kunzli *et al.* (2001) for a discussion of this issue). While some of the effects of short term exposure are likely to be captured by the cohort estimates, there may be additional premature mortality from short term PM exposure not captured in the cohort estimates included in the primary analysis.

[c] May result in benefits or disbenefits.

X. Economic Impacts

For the affected region, the projected annual private incremental costs of the proposed remedy option to the power industry are $3.7 billion in 2012 and $2.8 billion in 2014. For the State Budgets/Intrastate Trading remedy, projected annual private incremental costs are $4.2 billion in 2012 and $2.7 billion in 2014. Finally, for the direct control remedy, the projected annual private incremental costs are $4.3 billion in 2012 and $3.4 billion in 2014. These costs represent the private compliance cost to the electric generating industry of reducing NO_X and SO_2 emissions to meet the requirements set forth in the rule. Estimates are in 2006 dollars.

In estimating the net benefits of regulation, the appropriate cost measure is "social costs." Social costs represent the welfare costs of the rule to society. These costs do not consider transfer payments (such as taxes) that are simply redistributions of wealth. The social costs of this rule for the proposed remedy option are estimated to be approximately $2.0 billion in 2014 assuming a 3 percent discount rate. These costs become $2.2 billion in 2014 assuming a 7 percent discount rate. For the State Budgets/Intrastate Trading remedy, social costs are estimated to be approximately $2.5 billion in 2014 assuming a 3 percent discount rate and $2.7 billion in 2014 assuming a 7 percent discount rate. Finally, for the direct control remedy, social costs are estimated to be approximately $2.7 billion in 2014 assuming a 3 percent discount rate and $2.9 billion in 2014 assuming a 7 percent discount rate.

Overall, the economic impacts of the Transport Rule proposal are modest in 2014, particularly in light of the large benefits ($122 to $294 billion annually at a 3 percent discount rate and $111 to $266 billion annually at a 7 percent discount rate) we expect as shown earlier in this preamble (*see* section IX for more details). Ultimately, we believe the electric power industry will pass along most of the costs of the rule to consumers, so that the costs of the rule will largely fall upon the consumers of electricity. For more information on electricity price changes that result from this proposal, please refer to section XII.H (Statement of Energy Effects) later in this preamble.

For this proposed rule, EPA analyzed the costs using the Integrated Planning Model (IPM). The IPM is a dynamic linear programming model that can be used to examine the economic impacts of air pollution control policies for SO_2 and NO_X throughout the contiguous United States for the entire power system.

Documentation for IPM can be found in the docket for this rulemaking or at *http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.* Analysis of impacts on affected industries outside of the electric power generating sector are estimated by the Economic Model for Policy Analysis (EMPAX), a dynamic model that can generate price and output changes for output affected by electricity price changes due to air pollution control policies and also estimates of social costs associated with such policies. Documentation for EMPAX can be found in the docket for this rulemaking or at *http://www.epa.gov/ttn/ecas/EMPAX.htm.*

Also note that as explained in section IV.A.3, the baseline used in this analysis assumes no CAIR. If EPA's base case analysis were to assume that reductions from CAIR would continue indefinitely, areas that are in attainment solely due to controls required by CAIR would again face nonattainment problems because the existing protection from upwind pollution would not be replaced. As explained in that section, EPA believes that this is the most appropriate baseline to use for purposes of determining whether an upwind state has an impact on a downwind monitoring site in violation of section 110(a)(2)(D).

XI. Incorporating End-Use Energy Efficiency Into the Proposed Transport Rule

A. Background

EPA believes that achievement of energy efficiency improvements in homes, buildings, and industry is an important component of achieving emissions reductions from the power sector while minimizing associated compliance costs. By reducing electricity demand, energy efficiency avoids emissions of all pollutants associated with electricity generation, including emissions of NO_X and SO_2 targeted by this rule. While all remedy options considered—including the proposed remedy (State Budgets/Limited Trading)—will lead to a modest increase in the relative cost-effectiveness of energy efficiency investments by internalizing environmental costs associated with these pollutants, EPA is interested in considering additional means by which energy efficiency can be encouraged through this proposed rule.

1. What is end-use energy efficiency?

End-use energy efficiency (hereafter, "energy efficiency") in the context of this proposed rule refers to activities that reduce the demand for electricity from EGUs in affected states. Energy efficiency improvements are pursued through the efforts of state agencies, independent program administrators (*e.g.* Vermont Energy Investment Corporation), electric utilities, energy service companies, and other commercial entities. Examples of common energy efficiency projects include re-commissioning of commercial buildings, rebates for energy efficient appliances, and home energy audits.

2. How does energy efficiency contribute to cost-effective reductions of air emissions from EGUs?

EPA recognizes that significant opportunity remains for energy efficiency improvements in businesses, homes, and industry. However, there are several informational and market barriers that limit investment in cost-effective energy efficient practices. Several federal programs authorized under the Act, including ENERGY STAR, are designed to address these barriers.

By reducing the demand for electricity energy efficiency reduces the need for investments in EGU emissions control technologies in order to meet the limits of an established state emissions budget and can often be implemented at a lower cost than traditional control technologies. Section III.E in this preamble further discusses the importance of electricity demand reductions as a component of EPA's broader air quality improvement strategy for the power sector.

EPA is available to assist states in quantifying the reduction in compliance costs of air regulatory programs, including the proposed rule, that can be realized through effective energy efficiency policies and programs.

3. How does the proposed rule support greater investment in energy efficiency?

By requiring reductions in the emissions of NO_X and SO_2 from power plants in affected states, a transport rule will lead to the internalization of costs associated with reducing the environmental effects of these pollutants. Since the economics of energy efficiency investments are directly related to power generation costs, this will improve the relative cost-effectiveness of these investments. Over time, this effect is expected to lead to increases in energy efficiency investments and associated benefits.

4. How have EPA and states previously integrated energy efficiency into air regulatory programs?

Congress, EPA, and states have all recognized the value of incorporating energy efficiency into air regulatory programs. Several allowance-based programs—including the Acid Rain Program, EPA's NO_X Budget Trading program, and the Regional Greenhouse Gas Initiative (an effort of 10 states from the Northeast and Mid-Atlantic regions)—have provided mechanisms for rewarding energy efficiency projects through either the award of emissions allowances, typically through the use of a fixed set-aside pool, or the use of revenues obtained through the auction of emissions allowances. The emissions caps established by these programs are unaffected by this approach, however, compliance costs are reduced (to the extent electricity demand reductions are realized) as are the emissions of non-capped pollutants from affected EGUs. In addition to these allowance-based programs, EPA has also established, through Guidance,[116] a means for recognizing the emissions benefits of energy efficiency in SIPs and has approved their use in individual state plans.

B. Incorporating End-Use Energy Efficiency Into the Transport Rule

As discussed previously, EPA believes that increasing end-use energy efficiency can be an effective approach for reducing compliance costs of the proposed rule, as well as for reducing EGU emissions that are not the target of this rule including mercury, other toxics, and carbon dioxide. While EPA believes the proposed rule will make energy efficiency investments more competitive, the Agency is seeking comments on additional ways in which this rule could further encourage these investments.

1. Options that Could Be Used To Incorporate Energy Efficiency Into Allowance Based Programs

As discussed previously, allowance-based programs (such as the proposed State Budgets/Limited Trading remedy and the alternative State Budgets/Intrastate Trading remedy) of EPA and states have supported energy efficiency projects through the use of auction revenues or the award of allowances. EPA considered these options in developing this proposal but, for the reasons described later, decided not to include either option in this proposal.

2. Why did EPA not propose these options?

The emissions reductions requirements of the proposed rule are implemented through proposed FIPs. This means, among other things, that EPA allocates the emission allowances directly to individual sources. In contrast, when allowance based programs are implemented through SIPs, states may have significant flexibility to determine the methodology used to allocate or auction allowances in their budgets. Under the proposed FIPs, EPA would allocate allowances to sources in a manner consistent with the methodology used to determine each state's budget. EPA believes this approach is appropriate because of the link between the allowance allocation methodology and the significant contribution determinations. EPA requests comment on whether EPA has authority to and whether it would be appropriate for EPA to consider energy efficiency considerations in developing the allowance allocation methodology.

In addition, because the emission reduction requirements are implemented through FIPs, any auction of allowances would be conducted by EPA. As discussed previously in section V.D.5.b, pursuant to the Miscellaneous Receipts Act, any revenues from a federal auction of allowances must go to the U.S. Treasury. This precludes the use of proceeds from such an auction to reward energy efficiency projects.

In addition, and as also discussed previously in sections III.A and III.B.3, EPA anticipates further revisions to the $PM_{2.5}$ and ozone NAAQS and intends to issue subsequent proposals to address the interstate transport requirements of section 110(a)(2)(D)(i)(I) with respect to those new NAAQS. The emissions reductions requirements identified in any such rules could be implemented through SIPs. The SIP process could give states significant flexibility in regards to allocation and auctioning of allowances. This flexibility could be used by states to support energy efficiency projects through the use of auction revenues or the award of allowances.

EPA is seeking comment on the discussion within this section and the use of these and other approaches for encouraging energy efficiency within the proposed rule.

XII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4,

[116] U.S. EPA. 2004. Guidance on State Implementation Plan (SIP) Credits for Emission Reductions From Electric-Sector Energy Efficiency and Renewable Energy Measures. August. *http://www.epa.gov/ttn/oarpg/t1/memoranda/ereseerem_gd.pdf.*

1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action. In addition, EPA prepared a Regulatory Impact Analysis (RIA) of the potential costs and benefits associated with this action.

When estimating the $PM_{2.5}$- and ozone-related human health benefits and compliance costs in Table 1 below, EPA applied methods and assumptions consistent with the state-of-the-science for human health impact assessment, economics and air quality analysis. EPA applied its best professional judgment in performing this analysis and believes that these estimates provide a reasonable indication of the expected benefits and costs to the nation of the preferred and alternate Transport Rule remedies considered by the Agency. The Regulatory Impacts Analysis (RIA) available in the docket describes in detail the empirical basis for EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below.

When characterizing uncertainty in the PM-mortality relationship, EPA has historically presented a sensitivity analysis applying alternate assumed thresholds in the PM concentration-response relationship. In its synthesis of the current state of the PM science, EPA's 2009 Integrated Science Assessment (ISA) for Particulate Matter concluded that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship. In the RIA accompanying this rule, rather than segmenting out impacts predicted to be associated levels above and below a 'bright line' threshold, EPA includes a "lowest-measured-level (LML)" that illustrates the increasing uncertainty that characterizes impacts attributed to levels of $PM_{2.5}$ below the LML for each study. Figure 5–19 shows the distribution of avoided PM mortality impacts predicted relative to the baseline (*i.e.* pre-Transport Rule) $PM_{2.5}$ levels experienced by the population receiving the $PM_{2.5}$ mortality benefit in 2014 (Figure 5–19). This figure also shows the lowest air quality levels measured in each of the two primary epidemiological studies EPA uses to quantify PM-related mortality. This information allows readers to determine the portion of PM-related mortality benefits occurring above or below the LML of each study; in general, our confidence in the size of the estimated reduction $PM_{2.5}$-related premature mortality decreases in areas where annual mean $PM_{2.5}$ levels are further below the LML in the two epidemiological studies. In this analysis, we see that about 80% of the estimated benefits accrue among populations exposed to annual mean $PM_{2.5}$ levels above 10ug/m3 (the LML in the Six Cities study) and 97% of the estimated benefits are associated with PM levels above 7.5 mg/m3 (the LML in the American Cancer Society study used for this analysis). While the LML analysis provides some insight into the level of uncertainty in the estimated PM mortality benefits, EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations.

Table XII.A–1 shows the results of the cost and benefits analysis for the proposed and alternate remedies.

TABLE XII.A–1—SUMMARY OF ANNUAL BENEFITS, COSTS, AND NET BENEFITS OF VERSIONS OF THE PROPOSED REMEDY OPTION IN 2014 [a]

[Billions of 2006$]

Description	Preferred remedy-State budgets/limited trading	Direct control	Intrastate trading
Social costs [b]			
3% discount rate	$2.03	$2.68	$2.49.
7% discount rate	$2.23	$2.91	$2.70.
Health-related benefits [c,d]			
3% discount rate	$118 to $288 + B	$117 to $286 + B	$113 to $276 + B.
7% discount rate	$108 to $260 + B	$108 to $262 + B	$104 to $252 + B.
Net benefits (benefits-costs)			
3% discount rate	$116 to $286	$115 to $283	$110 to $273.
7% discount rate	$105 to $258	$105 to $259	$101 to $249.

Notes: (a) All estimates are rounded to three significant digits and represent annualized benefits and costs anticipated for the year 2014. For notational purposes, unquantified benefits are indicated with a "B" to represent the sum of additional monetary benefits and disbenefits. Data limitations prevented us from quantifying these endpoints, and as such, these benefits are inherently more uncertain than those benefits that we were able to quantify. A listing of health and welfare effects is provided in RIA Table 1–6. Estimates here are subject to uncertainties discussed further in the body of the document. (b) The social costs are the loss of household utility as measured in Hicksian equivalent variation. (c) The reduction in premature mortalities account for over 90% of total monetized benefits. Benefit estimates are national. Valuation assumes discounting over the SAB-recommended 20-year segmented lag structure described in Chapter 5. Results reflect 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (U.S. EPA, 2000; OMB, 2003). The estimate of social benefits also includes CO_2-related benefits calculated using the social cost of carbon, discussed further in chapter 5. Benefits are shown as a range from Pope *et al.* (2002) to Laden *et al.* (2006). Monetized benefits do not include unquantified benefits, such as other health effects, reduced sulfur deposition or visibility. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. (d) Not all possible benefits or disbenefits are quantified and monetized in this analysis. B is the sum of all unquantified benefits and disbenefits. Potential benefit categories that have not been quantified and monetized are listed in RIA Table 1–4.

B. Paperwork Reduction Act

The information collection requirements in the proposed rule have been submitted for approval to OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The information collection requirements are not enforceable until OMB approves them.

The information collection activities in this proposed rule include monitoring and the maintenance of records. The information generated by these activities will be used by EPA to ensure that affected facilities comply with the emission limits and other requirements. Records and reports are necessary to enable EPA or states to identify affected facilities that may not be in compliance with the requirements. Based on reported information, EPA will decide which units and what records or processes should be inspected. The amendments do not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to EPA for which a claim of confidentiality is made will be safeguarded according to EPA policies in 40 CFR part 2, subpart B, Confidentiality of Business Information.

The record-keeping and reporting burden to sources resulting from states choosing to participate in a regional cap-and-trade program is approximately $28 million annually. This estimate includes the annualized cost of installing and operating appropriate SO_2 and NO_X emissions monitoring equipment to measure and report the total emissions of these pollutants from affected EGUs (serving generators greater than 25 megawatt electrical). The burden to state and local air agencies includes any necessary SIP revisions, performance of monitoring certification, and fulfilling of audit responsibilities. More information on the ICR analysis is included in the proposed Transport Rule docket. Burden is defined at 5 CFR 1320.3(b).

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 in 40 CFR are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this proposed rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201. For the electric power generation industry, the small business size standard is an ultimate parent entity defined as having a total electric output of 4 million megawatt-hours (MW-hr) or less in the previous fiscal year.

(2) A small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and

(3) A small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

TABLE XII.C–1—POTENTIALLY REGULATED CATEGORIES AND ENTITIES [a]

Category	NAICS Code [b]	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal Government	[c] 221112	Fossil fuel-fired electric utility steam generating units owned by the federal government.
State/Local	[c] 221112	Fossil fuel-fired electric utility steam generating units owned by municipalities.
Tribal Government	921150	Fossil fuel-fired electric utility steam generating units in Indian Country.

[a] Include NAICS categories for source categories that own and operate electric generating units only.
[b] North American Industry Classification System.
[c] Federal, state, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

After considering the economic impacts of this proposed rule on small entities, EPA is certifying that this action will not have a significant economic impact on a substantial number of small entities. This certification is based on the economic impact of this proposed action to all affected small entities across all industries affected. EPA has assessed the potential impact of this action on small entities and found that approximately 550 of the estimated 4,700 EGUs potentially affected by today's proposal are owned by the 81 potentially affected small entities identified by EPA's analysis. EPA estimates that 30 of the 81 identified small entities will have annualized costs greater than 1 percent of their revenues, and the other 51 are projected to incur costs less than 1 percent of revenues. While there are costs greater than 1 percent of revenues for a number of small entities, EPA is certifying No SISNOSE for several reasons. First, of the 30 entities projected to have costs greater than 1 percent of revenues, around 75 percent of them operate in cost of service regions and would generally be able to pass any increased costs along to rate-payers. This is one of the primary reasons given in the Regulatory Impact Assessment for the Final Clean Air Interstate Rule (EPA–452/R–05–002 March 2005) that supported EPA's "No SISNOSE" certification in the final CAIR FIP rule on April 28, 2006 (71 FR 25366). Furthermore, of the approximately 550 units identified by EPA as being potentially owned by small entities, approximately two-thirds of the units that have higher costs are not expected to make operational changes as a result of this rule (*e.g.*, install control equipment or switch fuels). Their increased costs are largely due to increased cost of the fuel they would be expected to use whether or not they had to comply with the proposed rule. Further, increased fuel costs are often passed through to rate-payers as common practice in many areas of the United States due to fuel adder arrangements instituted by state public utility commissions. In addition, EPA's decision to exclude units smaller than 25 MWe has already significantly reduced the burden on small entities. Hence, EPA has concluded that there is no SISNOSE for this rule.

For more information on the small entity impacts associated with the proposed rule, please refer to the Economic Impact and Small Business Analyses in the public docket. These analyses can be found in the Regulatory Impact Analysis for this proposed rule. Finally, although EPA believes that the proposed rule would not have a significant economic impact on a substantial number of small entities, EPA plans to take steps to conduct meetings with industry trade associations to discuss regulatory options and ensure that the burdens imposed on small entities are minimal.

We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538, requires federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. This rule contains a Federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. Accordingly, EPA has prepared under section 202 of the UMRA a written statement which is summarized later.

Consistent with section 205, EPA has identified and considered a reasonable number of regulatory alternatives. In today's action, EPA has included three remedy options that it considered when developing this proposed rule: (1) The proposed remedy of State Budgets/Limited Trading, (2) State Budgets/Intrastate Trading, and (3) Direct Controls. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted.

EPA examined the potential economic impacts on state and municipality-owned entities associated with this rulemaking based on assumptions of how the affected states will implement control measures to meet their emissions. Although EPA does not conclude that the requirements of the UMRA apply to the Transport Rule, these impacts have been calculated to provide additional understanding of the nature of potential impacts and additional information.

According to EPA's analysis, of the 84 government entities considered in this analysis and the 482 government entities in the Transport Rule region that are included in EPA's modeling, 27 may experience compliance costs in excess of 1 percent of revenues in 2014, based on our assumptions of how the affected states implement control measures to meet their emissions budgets as set forth in this rulemaking.

Government entities projected to experience compliance costs in excess of 1 percent of revenues have some potential for significant impact resulting from implementation of the Transport Rule. However, as noted previously, it is EPA's position that because these government entities can pass on their costs of compliance to rate-payers, they will not be significantly affected. Furthermore, the decision to include only units greater than 25 MW in size exempts 380 government entities that would otherwise be potentially affected by the Transport Rule. For more information on the impacts estimated for this analysis, please refer to the RIA for this proposed rule.

In addition, before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA, a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements. Consistent with the intergovernmental consultation provisions of section 204 of the UMRA, EPA has initiated consultations with governmental entities affected by this rule.

The EPA has determined that this rule contains a Federal mandate that may result in expenditures of $100 million or more in 1 year. EPA has determined that this rule contains no regulatory requirements that might significantly or uniquely affect small governments and that development of a small government plan under section 203 of the Act is not required. The costs of compliance will be borne predominately by sources in the private sector although a small number of sources owned by state and local governments may also be impacted. The requirements in this action do not distinguish EGUs based on ownership, either for those units that are included within the scope of the rule or for those units that are exempted by the generating capacity cut-off. Therefore, this rule is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

This proposed rule does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The proposed rule primarily affects private industry, and does not impose significant economic costs on state or local governments. Thus, Executive Order 13132 does not apply to the proposed rule.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and state and local governments, EPA will specifically solicit comment on the proposed rule from state and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to the final rule.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

EPA interprets Executive Order 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it does not involve decisions on environmental health or safety risks that may disproportionately affect children. The EPA believes that the emissions reductions from the strategies in this rule will further improve air quality and will further improve children's health.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies shall prepare and submit to the Administrator of the Office of Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as "significant energy actions." Section 4(b) of Executive Order 13211 defines "significant energy action" as "any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) That is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action." This proposed rule is a significant regulatory action under Executive Order 12866, and this proposed rule may have a significant adverse effect on the supply, distribution, or use of energy.

Under the provisions of this proposed rule, EPA projects that approximately 1.2 GW of coal-fired generation may be removed from operation by 2014. In practice, however, the units projected to be uneconomic to maintain may be "mothballed," retired, or kept in service to ensure transmission reliability in certain parts of the grid. These units are predominantly small and infrequently used generating units dispersed throughout the area affected by the rule. Assumptions of higher natural gas prices or electricity demand would create a greater incentive to keep these units operational. The EPA projects that the average retail electricity price could increase nationally by less than 2.5 percent in 2012 and 1.5 percent in 2014. This is generally less of an increase than often occurs with fluctuating fuel prices and other market factors. Related to this, delivered coal prices increase by about 7 percent in 2012 and 4 percent in 2014 as a result of higher demand for lower-sulfur coals. The EPA also projects that natural gas prices will increase by less than 1.7 percent in 2012 and 0.5 percent in 2014 and that natural gas use for electricity generation will increase by less than 73 million mcf by 2014. The price increase is also within the range we regularly see in delivered natural gas prices. Finally, the EPA projects coal production for use by the power sector, a large component of total coal production, will decrease by 3 million tons in 2012 and 9 million tons in 2014. The EPA does not believe that this rule will have any other impacts that exceed the significance criteria.

The EPA believes that a number of features of the proposed rulemaking serve to reduce its impact on energy supply. First, the trading programs in State Budgets/Limited Trading provide considerable flexibility to the power sector and enable industry to comply with the emission reduction requirements in the most cost-effective manner, thus minimizing overall costs and the ultimate impact on energy supply. Second, the more stringent budgets for SO_2 are set in two phases, providing adequate time for EGUs to install pollution controls. In addition, both the operational flexibility of trading and the ability to bank allowances for future years helps industry plan for and ensure reliability in the electrical system. For more details concerning energy impacts, *see* the RIA for the proposed Transport Rule.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law 104–113, 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. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This proposed rule would require all sources to meet the applicable monitoring requirements of 40 CFR part 75. Part 75 already incorporates a number of voluntary consensus standards.

Consistent with the Agency's Performance Based Measurement System (PBMS), 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. At this time, EPA is not recommending any revisions to Part 75; however, EPA periodically revises the test procedures set forth in Part 75.

When EPA revises the test procedures set forth in Part 75 in the future, EPA will address the use of any new voluntary consensus standards that are equivalent. Currently, even if a test procedure is not set forth in Part 75, 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 through the petition process under 40 CFR 75.66 before they are used.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority, low-income, and Tribal populations in the United States.

1. Consideration of Environmental Justice Issues in the Rule Development Process

In the rulemaking process, EPA considers whether there are positive or negative impacts of the action that appear to affect low-income, minority, or Tribal communities disproportionately, and, regardless of whether a disproportionate effect exists, whether there is a chance for these communities to meaningfully participate in the rulemaking process. EPA expects that this rule, "Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone," will provide significant health and environmental benefits to, among others, people with asthma, people with heart disease, and people living in ozone or fine particle ($PM_{2.5}$) nonattainment areas. This rule also has the potential to affect the cost structure of the utility industry and could lead to regional shifts in electricity generation and/or emissions of various pollutants. Therefore we expect this rule to be of interest to many environmental justice communities. EPA's analysis of the effects of this proposed rule, including information on air quality changes and the resulting health benefits, is presented both in section IX of this preamble and in more detail in the air quality modeling Technical Support Document and the Regulatory Impact Analysis (RIA) for this rule. These documents can be accessed through the rule docket No. EPA–HQ–OAR–2009–0491 and from the main EPA Web page for the rule *http://www.epagov/airtransport.* This section summarizes the legal basis for this rule, and provides background information on how this rule fits into the larger regulatory strategy for controlling pollution from the power sector. A summary of the emissions, air quality, and health benefit estimates for this rule then follows.

This rule is replacing an earlier rule (the 2005 Clean Air Interstate Rule (CAIR)) that was first vacated and then remanded to EPA by the U.S. Court of Appeals for the District of Columbia Circuit. CAIR was vacated by the U.S. Court of Appeals for the District of Columbia Circuit in July 2008 in a case known as *North Carolina* v. *EPA.* In December 2008, the vacatur was altered to a remand based on the likely environmental harms of vacating the rule and EPA's stated intent to replace the rule promptly. At the time of the 2008 court ruling, many sources had already begun to install and run emissions control devices or otherwise alter their operations and had successfully begun reducing their emissions. The court decision has led to significant uncertainty among affected sources as to what emissions reductions will be required and among states and communities as to what air quality benefits will be achieved. By proposing this aggressive replacement rule that meets the legal requirements of the CAA as interpreted by the Court in the *North Carolina* decision promptly, EPA is both maximizing the likelihood that the goals of the CAA will be met, and helping communities receive the air quality benefits they need as quickly as possible by minimizing the chance that any emissions reductions achieved under CAIR would be lost.

It is important to note that CAA section 110(a)(2)(d), which addresses transport of criteria pollutants between states and is the authority for this rule, is only one of many provisions of the CAA that provide EPA, states, and local governments with authorities to reduce exposure to ozone and $PM_{2.5}$ in communities. These legal authorities work together to reduce exposure to these pollutants in communities, including environmental justice communities, and provide substantial health benefits to both the general public and sensitive sub-populations.

This proposed rule is one of a group of regulatory actions that EPA will take over the next several years to respond to statutory and judicial mandates that will reduce exposure to ozone and $PM_{2.5}$, as well as to other pollutants, from power plants and other sources. To the extent that EPA has the legal authority to do so while fulfilling its obligations under the CAA and other relevant statutes, we will also coordinate these utility-related air pollution rules with upcoming regulations for the power sector from EPA's Office of Water (OW) and its Office of Resource Conservation and Recovery (ORCR). The primary actions are outlined below and presented in more detail in section III.E of this preamble.

Beyond this action and any additional efforts undertaken in response to comment, other rules that will drive the creation of a clean, efficient and completely modern power sector include: CAA section 112(d) standards (one of which is often referred to as a Maximum Achievable Control Technology (MACT) standard) to reduce emissions of air toxics, including mercury, and particles from coal- and oil-fired power plants; new National Ambient Air Quality Standards (NAAQS) for ozone, $PM_{2.5}$, sulfur dioxide, and nitrogen oxides; potentially one or more additional rules eliminating interstate transport of emissions that contribute significantly to nonattainment and maintenance areas for the new ozone and $PM_{2.5}$ NAAQS as necessary; revisions to the New Source Performance Standards (NSPS) for steam electric generating units; and best available retrofit technology (BART) requirements and other requirements that address visibility and regional haze. Within the planning and investment horizon for compliance with these rules, EPA very likely will be compelled to respond to a pending petition to set standards for the emissions of greenhouse gases (GHGs) from steam electric generating units under the New Source Performance Standard program. Furthermore, as set forth in the recently promulgated reinterpretation of the Johnson Memo, beginning in 2011 new and modified sources of GHG emissions, including EGUs, will be subject to permits under the Prevention of Significant Deterioration program requiring them to adopt Best Available Control Technology for their GHGs. Finally, EPA will pursue energy efficiency improvements in the use of electricity throughout the economy, along with other federal agencies, states and other groups, which will contribute to additional environmental and public health improvements that the Agency wants to provide while lowering the costs of realizing those improvements.

Together, these rules and actions will have substantial and long-term effects on both the U.S. power industry and on communities currently breathing dirty air. Therefore, we anticipate significant interest in many, if not most, of these actions from environmental justice communities, among many others. EPA intends to provide multiple opportunities for comment on these actions, including during the comment process for this rule, and encourages environmental justice communities to review and comment on them.

2. Potential Environmental and Public Health Impacts to Vulnerable Populations

There are several considerations to take into account when assessing the effects of this proposed rule on minority, low-income, and tribal populations. These include: Amount of emissions reductions and where they take place (including any potential for areas of increased emissions); the changes in ambient concentrations across the affected area; and the health benefits expected from the rules.

Emissions reductions. This proposed rule will reduce exposure to $PM_{2.5}$ and ozone pollution in most eastern states by reducing interstate transport of these pollutants and their chemical precursors (sulfur dioxide (SO_2) and nitrogen oxides (NO_X)). This rule has the effect of reducing emissions of these pollutants that affect the most-contaminated areas (*i.e.* areas that are not meeting the 1997 and 2006 ozone and $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS)). This rule separately identifies both nonattainment areas and maintenance areas (maintenance areas are those that currently meet the NAAQS but that, based on past data, are in danger of exceeding the standards in the future). This approach of requiring emissions reductions to protect maintenance areas as well as nonattainment areas reduces the likelihood that any areas close to the level of the standard will exceed the current health-based standards in the future.

Ozone and $PM_{2.5}$ concentrations in both nonattainment and maintenance areas identified in this rule are the result of both local emissions and long-range transport of pollution. This rule requires upwind states to reduce or eliminate their significant contribution to nonattainment or maintenance problems in downwind states. Even when the significant contributions of upwind states are fully eliminated, additional emissions reductions within the nonattainment area and/or the downwind state will be needed for some areas to attain and maintain the NAAQS.

The proposed remedy option for this rule would use a limited emissions trading mechanism among power plants to achieve significant emissions reductions in states covered by the rule. EPA recognizes that many environmental justice communities have voiced concerns about emissions trading and any resulting potential for any emissions increases in any location.

This proposed rule uses EPA's authority in CAA § 110(a)(2)(d) to require states to eliminate emissions from power plants in their state that contribute significantly to downwind $PM_{2.5}$ or ozone nonattainment or maintenance areas. EPA's proposed mechanism for achieving these emissions reductions is to use a tightly constrained trading program that requires a strict emission ceiling in each state while allowing a limited ability to shift emissions between facilities or states. This approach ensures that emissions in each state that significantly contribute to downwind nonattainment or maintenance areas are controlled, while allowing power companies to adjust generation based on fluctuations in electricity demand, weather, availability of low-emitting power sources (*e.g.* temporary shut-down of a nuclear power plant for maintenance or repairs), or other unanticipated factors affecting the interconnected electricity grid.

Any emissions above the state's allocated level must be offset by emissions reductions from another state in the region below that state's budget or by using extra "banked" allowances from earlier years. All sources must hold enough allowances to cover their emissions; therefore, if they emit more than their allocation they must buy allowances from another source that emitted less than its allocation. $PM_{2.5}$ and ozone pollution from power plants have both local and regional components: Part of the pollution in a given location—even in locations near emissions sources—is due to emissions from nearby sources and part is due to emissions that travel hundreds of miles and mix with emissions from other sources. Therefore, in many instances the exact location of the upwind reductions does not affect the levels of air pollution downwind.

It is important to recognize that the section of the Clean Air Act providing authority for this rule, 110(a)(2)(D), unlike some other provisions, does not dictate levels of control for particular facilities. None of EPA's alternatives within this proposal can ensure there will be no emission increases at any facility. Under the direct control alternative, the emissions rate for each facility is reduced but each facility could emit more by increasing their power output in order to meet electricity reliability or other goals. Under the intrastate trading option, state emissions must stay constant but individual facilities within each state could increase their emissions as long as another facility in the state had decreased theirs. By strictly setting state budgets to eliminate significant contributions to non-attainment and maintenance areas that EPA has identified in this action, by limiting the amount of interstate trading possible and by requiring any emissions above the level of the allocations to be offset by emission decreases elsewhere in the region, the proposed remedy options reduce ambient concentrations where they are most needed.

EPA's emissions modeling data indicate that nationwide SO_2 emissions from electric generating units (EGUs) will be approximately 6.4 million tons (60 percent) lower in 2014 than they were in 2005 (which is the year that the Clean Air Interstate Rule was finalized). Emissions would also decrease when compared to the base case (the base case estimates of SO_2 emissions in 2014 in the absence of this proposed rule or the Clean Air Interstate Rule it is replacing). SO_2 emissions under this proposed rule are projected to be approximately 4.4 million tons (50%) lower than they would have been in 2014 in the base case (*i.e.* without this rule).

EPA's modeling does project that some states not covered by one or more aspects of the program may experience increases of SO_2 emissions (*i.e.*, their emissions are greater in the control case modeling than in the base case modeling). These emission increases are the result of forecasted changes in operation of units outside of the controlled region (due to the interconnected nature of the utility grid or influence of the rule on the market for lower sulfur coal). As shown in Table IV.D.6, Arkansas, Mississippi, North Dakota, South Dakota, and Texas all exhibit 2012 SO_2 emissions increases over the base case of more than 5,000 tons. Texas is projected to have by far the largest increase (136,000 tons), while the other states' increases ranges from 6,000 to 32,000 tons. Further analysis with the simplified air quality assessment tool indicates that these projected increases in the Texas SO_2 emissions would increase Texas's contribution to an amount that would exceed the 0.15 $\mu g/m^3$ threshold for annual $PM_{2.5}$. For this reason, EPA requests comment on whether Texas should be included in the program as a group 2 state. For additional details, *see* section IV.D of this preamble.

With the exception noted above, EPA is not proposing for the SO_2 portion of this rule to cover the states where SO_2 emissions are projected to increase because EPA has not found, at this time, that they contribute significantly to nonattainment or interfere with maintenance of the $PM_{2.5}$ NAAQS in downwind areas. EPA's authority under § 110(a)(2)(d)(i)(I) is limited to addressing any such significant contribution and interference with maintenance. EPA anticipates that additional rulemakings affecting utilities that will be proposed soon, such as the CAA Section 112(d) standards, would apply nationwide and result in significant additional SO_2 reductions.

EPA's emissions modeling data indicates that nationwide ozone season NO_X emissions from EGUs will be approximately 400,000 tons (30%) lower in 2014 than they were in 2005 (before implementation of the Clean Air Interstate Rule). Emissions would also decrease compared to the base case. Ozone season NO_X emissions from EGUs under this proposed rule are projected to be approximately 150,000 tons (15%) lower than they would have been in 2014 in the base case (*i.e.* without this rule). EPA anticipates that additional upcoming actions, and likely additional interstate transport reductions to help states attain the proposed 2010 ozone NAAQS, will result in significant additional NO_X reductions.

EPA anticipates that this proposed action will significantly reduce, but not eliminate, the number of nonattainment and maintenance areas for the 1997 ozone and $PM_{2.5}$ and 2006 $PM_{2.5}$ NAAQS. Table IX–1 lists the changes in number of nonattainment sites. Most of these sites are located in urban areas. A single nonattainment area usually contains multiple monitoring sites; therefore there are more nonattainment sites than nonattainment counties or areas. As discussed in detail in section IV.D of this preamble, where this proposal does not fully quantify all of the significant contribution and interference with maintenance, EPA intends to address these additional requirements quickly. To the extent possible, EPA will supplement this proposed notice with additional information so that we can provide downwind states with all the certainty about upwind emissions reductions they need to address their own local nonattainment concerns. In addition, as stated above, elimination of these nonattainment areas may require both local and regional emissions reductions and this proposed action seeks only to address the regional transport component.

As a result of these SO_2 and NO_X reductions, EPA's air quality modeling indicates that concentrations of fine particles will decline throughout the eastern U.S. and in all the states affected by this rule. These reductions are largest in the area of the Ohio River valley and neighboring states and extend east through New England, west to Texas, south to Florida, and north through the Great Lakes states. "Border" states immediately outside the transport region are also predicted to see reductions in air concentrations, even though emissions increase in some of these states. This is because concentrations of fine particles in most locations are composed of both local emissions and those transported over hundreds of miles and emissions reductions far away can cause significant improvements in local air quality.

The modeling suggests also that there may be some small increases in $PM_{2.5}$ near locations in the western U.S. where SO_2 emissions are forecast to increase. These increases are small compared to the reductions predicted to take place in the eastern U.S. The increases are due to the regional nature of this rule (*i.e.* these states are not covered because sources in these states have not been found to contribute significantly to downwind nonattainment or maintenance areas) and the national nature of both coal markets and the Acid Rain Program allowance market. They are not the result of any particular type of remedy option (*e.g.* trading). EPA anticipates that future rulemakings, such as CAA section 112(d) standards and anticipated revisions to the 2006 fine particulate standards, are likely to reduce emissions in the areas not covered by this rule.

EPA's air quality modeling also indicates that concentrations of ozone will decline in much of the eastern U.S. These reductions are largest along much of the Gulf Coast and in Florida and in a region encompassing western Wisconsin, Iowa, Kansas, Missouri, Arkansas, and northeastern Oklahoma. These areas with the largest reductions are roughly the area immediately outside the boundaries of the NO_X SIP Call region. States in the SIP Call region were required to make significant reductions in NO_X beginning in 2003 and these emissions reductions are included in the baseline modeling for this proposed Transport Rule and therefore not captured as additional benefits of this rulemaking.

As is common when modeling many NO_X control strategies, the air quality modeling for this proposed rule also suggests there may be a few small, localized areas in the eastern U.S. where there are small increases in ozone concentrations. These generally small increases are a result of reductions in NO_X emissions in these local areas; they do not appear to represent a lack of NO_X emissions reductions or be the result of any specific emission control strategy (*e.g.* any type of trading). Rather, this phenomenon can result from complex atmospheric chemistry reactions taking place among chemical constituents of air pollution in these areas. Due to the complex photochemistry of ozone production, NO_X emissions lead to both the formation and destruction of ozone, depending on the relative quantities of NO_X, volatile organic compounds, and ozone formation catalysts. In the 2014 base case, NO_X emissions from sources in a few locations act to "quench" (*i.e.*, lower) ozone compared to ozone concentrations in surrounding areas. The application of NO_X controls in these areas reduces this quenching effect, thereby increasing ozone to levels generally on par with those of the surrounding area. In this case it is uncertain whether the structure of the model itself is potentially exacerbating the spatial extent or magnitude of any ozone increases which might actually occur as a result of this rule. It should be noted that these same NO_X emissions reductions that might be causing extremely localized ozone increases are certainly causing larger, more widespread improvements in ozone concentrations in downwind areas. Finally, as stated above, it is important to note that EPA intends to promulgate additional rules over the next few years that will further reduce concentrations of ozone and $PM_{2.5}$ and that the federal government and the states can and do use many different legal authorities to limit exposure to ozone.

Health benefits. This rule reduces concentrations of $PM_{2.5}$ and ozone pollution, exposure to which can cause, or contribute to, adverse health effects including premature mortality and many types of heart and lung diseases that affect many minority and low-income individuals, and Tribal communities. $PM_{2.5}$ and ozone are particularly (but not exclusively) harmful to children, the elderly, and people with existing heart and lung diseases, including asthma. Exposure to these pollutants can cause premature death and trigger heart attacks, asthma attacks in those with asthma, chronic and acute bronchitis, emergency room visits and hospitalizations, as well as milder illnesses that keep children home from school and adults home from work. High rates of both heart disease and asthma are a cause for concern in many environmental justice communities, making these populations more susceptible to air pollution health impacts. In addition, many individuals in these communities also lack access to high quality health care to treat these illnesses.

We estimate that in 2014 the PM-related annual benefits of the proposed remedy option include approximately 14,000 to 36,000 fewer premature mortalities, 9,200 fewer cases of chronic bronchitis, 22,000 fewer non-fatal heart attacks, 11,000 fewer hospitalizations (for respiratory and cardiovascular disease combined), 10 million fewer days of restricted activity due to respiratory illness and approximately 1.8 million fewer lost work days. We also estimate substantial health improvements for children in the form of fewer cases of upper and lower respiratory illness, acute bronchitis, and asthma attacks.

Ozone health-related benefits are expected to occur during the summer ozone season (usually ranging from May to September in the eastern U.S.). Based upon modeling for 2014, annual ozone related health benefits are expected to include between 50 and 230 fewer premature mortalities, 690 fewer hospital admissions for respiratory illnesses, 230 fewer emergency room admissions for asthma, 300,000 fewer days with restricted activity levels, and 110,000 fewer days where children are absent from school due to illnesses. When adding the PM and ozone-related mortalities together, we find that the proposed remedy option for this rule will yield between 14,000 and 36,000 fewer premature mortalities. EPA has also estimated the benefits of the alternate remedies in this proposal using a benefit-per-ton estimation approach and found they would provide similar benefits.

It should be noted that, as discussed in the RIA for this action, there are other benefits to the emissions reductions discussed here, such as improved visibility and, indirectly, reduced mercury deposition. Additional benefits of reducing emissions of SO_2 include reduced acidification of lakes and streams, and reduced mercury methylation; additional benefits of NO_X reductions include reduced acidification of lakes and streams and reduced coastal eutrophication. Conversely, it is possible that the modest increases in emissions modeled for this rule in some western areas could result in limited increases of one or more of these effects in these locations.

3. Meaningful Public Participation

As EPA began considering approaches to address the court remand of the 2005 Clean Air Interstate Rule, the agency also began gathering input from a larger range of stakeholders. In the spring of 2009, EPA held a series of listening sessions to gather information and perspectives from stakeholders prior to the formal start of the rulemaking process. These stakeholders included a number of environmental groups who requested that EPA consider several potential environmental justice issues during development of this rule. In addition, many environmental justice organizations were represented at a November 2009 EPA-Health and Human Services White House Stakeholder Briefing entitled "The Public Health Benefits of Energy Reform" in which EPA discussed our intention to propose this rule in the spring of 2010 and participants had the opportunity to respond. Finally, EPA notified tribes of our intent to propose this rule in the fall of 2009 during a regularly scheduled meeting to update the National Tribal Air Association members of upcoming EPA policies and regulations and to receive input from them on the effects of these efforts in Indian country. These were not opportunities for stakeholders to comment on the specifics of this proposal, as they took place prior to the development of this proposal, but they provided valuable information that EPA used in developing this proposal.

Upon proposal of this action, the Agency will begin an outreach effort with environmental justice communities, the public, the regulated community, state air regulators, and others to (1) describe the Transport Rule proposal, (2) provide information on the 2011 CAA Section 112 (d) and other upcoming EPA rulemakings affecting the power sector, and (3) listen to comments from stakeholders. The intent will be to inform all stakeholders of the industry's obligations and opportunities for the industry to use investments in SO_2 and NO_X reductions to help smooth transition to the CAA Section 112(d) standards compliance in late 2014. EPA intends to continue these efforts over time as more information becomes available in the development of the various rulemakings under development for the power sector.

During the comment period for this proposed rule, EPA intends to reach out specifically to environmental justice communities and organizations to notify them of the opportunity to provide comments on this rule and to solicit their comments on both this rule and the upcoming actions described above and in section III.E. EPA will hold public hearings on this rule; see the information at the very beginning of this preamble for locations, times and dates. Comments can also be submitted in writing or electronically by following the instructions at the beginning of this preamble.

4. Summary

EPA believes that the vast majority of communities and individuals in areas covered by this rule, including numerous low-income, minority, and Tribal communities in both rural areas and inner cities in the East, will see significant improvements in air quality and resulting improvements in health. EPA also recognizes that there is the potential for a number of communities or individuals outside the region covered by this rule to experience slightly worse air quality as an indirect result of emissions reductions required under this proposal. EPA requests comment on the impacts of this proposed action on low income, minority, and Tribal communities. EPA will further analyze environmental justice issues related to the impacts of the rule on those communities based both on additional data that may be developed and on comments on those issues prior to final action on this rule.

List of Subjects

40 CFR Part 51

Administrative practice and procedure, Air pollution control, Intergovernmental relations, Nitrogen oxides, Ozone, Particulate matter, Regional haze, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 52

Administrative practice and procedure, Air pollution control, Intergovernmental relations, Nitrogen oxides, Ozone, Particulate matter, Regional haze, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Parts 72

Acid rain, Administrative practice and procedure, Air pollution control, Electric utilities, Intergovernmental relations, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 78

Acid rain, Administrative practice and procedure, Air pollution control, Electric utilities, Intergovernmental relations, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 97

Administrative practice and procedure, Air pollution control, Electric utilities, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: July 6, 2010.

Lisa P. Jackson,

Administrator.

For the reasons set forth in the preamble, parts 51, 52, 72, 78, and 97 of chapter I of title 40 of the Code of Federal Regulations are proposed to be amended as follows:

PART 51—[AMENDED]

1. The authority citation for Part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

§ 51.121 [Amended]

2. Section 51.121 is amended by revising paragraph (r)(2) by removing the words "§ 51.123(bb)" and adding, in their place, the words "§ 51.123(bb) with regard to an ozone season that occurs before January 1, 2012".

§ 51.123 [Amended]

3. Section 51.123 is amended by adding a new paragraph (ff) to read as follows:

§ 51.123 Findings and requirements for submission of State implementation plan revisions relating to emissions of oxides of nitrogen pursuant to the Clean Air Interstate Rule.

* * * * *

(ff) Notwithstanding any provisions of paragraphs (a) through (ee) of this section, subparts AA through II and AAA through III of part 96 of this chapter, subparts AA through II and AAAA through IIII of part 97 of this chapter, and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011, the Administrator:

(i) Rescinds the determination in paragraph (a) of this section that the States identified in paragraph (c) of this section must submit a SIP revision with respect to the fine particles ($PM_{2.5}$) NAAQS and the 8-hour ozone NAAQS meeting the requirements of paragraphs (b) through (ee) of this section; and

(ii) Will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 96 of this chapter, subparts AA through II and AAAA through IIII of part 97 of this chapter, or in any emissions trading program provisions in a State's SIP approved under this section; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

§ 51.124 [Amended]

4. Section 51.124 is amended by adding a new paragraph (s) to read as follows:

§ 51.124 Findings and requirements for submission of State implementation plan revisions relating to emissions of sulfur dioxide pursuant to the Clean Air Interstate Rule.

* * * * *

(s) Notwithstanding any provisions of paragraphs (a) through (r) of this section, subparts AAA through III of part 96 of this chapter, subparts AAA through III of part 97 of this chapter, and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011, the Administrator:

(i) Rescinds the determination in paragraph (a) of this section that the States identified in paragraph (c) of this section must submit a SIP revision with respect to the fine particles ($PM_{2.5}$) NAAQS meeting the requirements of paragraphs (b) through (r) of this section; and

(ii) Will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 96 of this chapter, subparts AAA through III of part 97 of this chapter, or in any emissions trading program in a State's SIP approved under this section; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

§ 51.125 [Reserved]

5. Section 51.125 is removed and reserved.

PART 52—[AMENDED]

6. The authority citation for Part 52 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart A—General Provisions

§ 52.35 [Amended]

7. Section 52.35 is amended by adding a new paragraph (f) to read as follows:

§ 52.35 What are the requirements of the Federal Implementation Plans (FIPs) for the Clean Air Interstate Rule (CAIR) relating to emissions of nitrogen oxides?

* * * * *

(f) Notwithstanding any provisions of paragraphs (a) through (d) of this section, subparts AA through II and AAAA through IIII of part 97 of this chapter, and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) through (d) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

§ 52.36 [Amended]

8. Section 52.36 is amended by adding a new paragraph (e) to read as follows:

§ 52.36 What are the requirements of the Federal Implementation Plans (FIPs) for the Clean Air Interstate Rule (CAIR) relating to emissions of sulfur dioxide?

* * * * *

(e) Notwithstanding any provisions of paragraphs (a) through (c) of this section, subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraphs (a) through (e) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

9. Subpart A is amended by adding §§ 52.37 and 52.38 to read as follows:

§ 52.37 What are the requirements of the Federal Implementation Plans (FIPs) under the Transport Rule (TR) relating to emissions of nitrogen oxides?

(a)(1) The TR NO_X Annual Trading Program provisions of part 97 of this chapter constitute the TR Federal Implementation Plan provisions that relate to annual emissions of nitrogen oxides (NO_X).

(2) The provisions of subpart AAAAA of part 97 of this chapter, regarding the TR NO_X Annual Trading Program, apply to the sources in the following States: Alabama, Connecticut, Delaware, District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

(3) Following promulgation of an approval by the Administrator of a State's SIP as correcting the SIP's deficiency that is the basis for this Federal Implementation Plan, the provisions of paragraph (a)(2) of this section will no longer apply to the sources in the State, unless the Administrator's approval of the SIP is partial or conditional.

(4) Notwithstanding the provisions of paragraph (a)(3) of this section, if, at the time of such approval of the State's SIP, the Administrator has already allocated any TR NO_X Annual allowances to sources in the State for any years, the provisions of part 97 of this chapter authorizing the Administrator to complete the allocation of TR NO_X Annual allowances for those years shall continue to apply, unless provided otherwise by such approval of the State's SIP.

(b)(1) The TR NO_X Ozone Season Trading Program provisions of part 97 of this chapter constitute the TR Federal Implementation Plan provisions that relate to emissions of NO_X during the ozone season, defined as May 1 through September 30 of a calendar year.

(2) The provisions of subpart BBBBB of part 97 of this chapter, regarding the TR NO_X Ozone Season Trading Program, apply to sources in each of the following States: Alabama, Arkansas, Connecticut, Delaware, District of Columbia, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maryland, Michigan, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West Virginia.

(3) Following promulgation of an approval by the Administrator of a State's SIP as correcting the SIP's deficiency that is the basis for this Federal Implementation Plan, the provisions of paragraph (b)(2) of this section will no longer apply to sources in the State, unless the Administrator's approval of the SIP is partial or conditional.

(4) Notwithstanding the provisions of paragraph (b)(3) of this section, if, at the time of such approval of the State's SIP, the Administrator has already allocated any TR NO_X Ozone Season allowances to sources in the State for any years, the provisions of part 97 of this chapter authorizing the Administrator to complete the allocation of TR NO_X Ozone Season allowances for those years shall continue to apply, unless provided otherwise by such approval of the State's SIP.

§ 52.38 What are the requirements of the Federal Implementation Plans (FIPs) for the Transport Rule (TR) relating to emissions of sulfur dioxide?

(a) The TR SO_2 Group 1 Trading Program and TR SO_2 Group 2 Trading Program provisions of part 97 of this chapter constitute the TR Federal Implementation Plan provisions that relate to emissions of sulfur dioxide (SO_2).

(b) The provisions of subpart CCCCC of part 97 of this chapter, regarding the TR SO_2 Group 1 Trading Program, apply to sources in each of the following States: Georgia, Illinois, Indiana, Iowa, Kentucky, Michigan, Missouri, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin.

(c) The provisions of subpart DDDDD of part 97 of this chapter, regarding the TR SO_2 Group 2 Trading Program, apply to sources in each of the following States: Alabama, Connecticut, Delaware, District of Columbia, Florida, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Nebraska, New Jersey, and South Carolina.

(d) Following promulgation of an approval by the Administrator of a State's SIP as correcting the SIP's deficiency that is the basis for this Federal Implementation Plan, the provisions of paragraph (b) and (c) of this section, as applicable, will no longer apply to sources in the State, unless the Administrator's approval of the SIP is partial or conditional.

(e) Notwithstanding the provisions of paragraph (d) of this section, if, at the time of such approval of the State's SIP, the Administrator has already allocated any TR SO_2 Group 1 allowances or any TR SO_2 Group 2 allowances (as applicable) to sources in the State for any years, the provisions of part 97 of this chapter authorizing the Administrator to complete the allocation of TR SO_2 Group 1 allowances or TR SO_2 Group 2 allowances (as applicable) for those years shall continue to apply, unless provided otherwise by such approval of the State's SIP.

Subpart I—Delaware

10. Section 52.440 is amended by adding a new paragraph (c) to read as follows:

§ 52.440 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

11. Section 52.441 is amended by designating the introductory text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.441 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

Subpart J—District of Columbia

12. Section 52.484 is amended by adding a new paragraph (c) to read as follows:

§ 52.484 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

13. Section 52.485 is amended by designating the introductory text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.485 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

Subpart P—Indiana

14. Section 52.789 is amended by adding a new paragraph (c) to read as follows:

§ 52.789 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

15. Section 52.790 is amended by designating the introductory text as

paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.790 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

Subpart T—Louisiana

16. Section 52.984 is amended by adding a new paragraph (c) to read as follows:

§ 52.984 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

Subpart X—Michigan

17. Section 52.1186 is amended by adding a new paragraph (c) to read as follows:

§ 52.1186 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

18. Section 52.1187 is amended by designating the introductory text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.1187 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

Subpart FF—New Jersey

19. Section 52.1584 is amended by adding a new paragraph (c) to read as follows:

§ 52.1584 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

20. Section 52.1185 is amended by designating the introductory text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.1585 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

Subpart RR—Tennessee

21. Section 52.2240 is amended by adding a new paragraph (c) to read as follows:

§ 52.2240 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X

allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

22. Section 52.2241 is amended by designating the introductory text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.2241 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

Subpart SS—Texas

23. Section 52.2283 is amended by adding a new paragraph (c) to read as follows:

§ 52.2283 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraph (a) of this section relating to NO_X annual emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances allocated for 2012 or any year thereafter.

24. Section 52.2284 is amended by designating the introductory text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.2284 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

Subpart YY—Wisconsin

25. Section 52.8587 is amended by adding a new paragraph (c) to read as follows:

§ 52.8587 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) Notwithstanding any provisions of paragraphs (a) and (b) of this section and subparts AA through II and AAAA through IIII of part 97 of this chapter to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions in paragraphs (a) and (b) of this section relating to NO_X annual or ozone season emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2012 or any year thereafter.

26. Section 52.8588 is amended by designating the introductory text as paragraph (a) and adding a new paragraph (b) to read as follows:

§ 52.8588 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of sulfur dioxide?

* * * * *

(b) Notwithstanding any provisions of paragraph (a) of this section and subparts AAA through III of part 97 of this chapter and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2011,

(i) The provisions of paragraph (a) of this section relating to SO_2 emissions shall not be applicable; and

(ii) The Administrator will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 97 of this chapter; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2012 or any year thereafter.

PART 72—[AMENDED]

27. The authority citation for Part 72 is revised to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7411, 7426, 7601, *et seq.*

§ 72.2 [Amended]

28. Section 72.2 is amended by removing the definition of "interested person".

PART 78—[AMENDED]

29. The authority citation for Part 78 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7411, 7426, 7601, *et seq.*

§ 78.1 [Amended]

30. Section 78.1 is amended by adding paragraphs (b)(13) through (b)(16) to read as follows:

§ 78.1 Purpose and scope.

* * * * *

(b) * * *

(13) Under subpart AAAAA of part 97 of this chapter,

(i) The decision on allocation of TR NO_X Annual allowances under § 97.411(a)(2) and (b) of this chapter.

(ii) The decision on the transfer of TR NO_X Annual allowances under § 97.423 of this chapter.

(iii) The decision on the deduction of TR NO_X Annual allowances under §§ 97.424 and 97.425 of this chapter.

(iv) The correction of an error in an Allowance Management System account under § 97.427 of this chapter.

(iv) The adjustment of information in a submission and the decision on the deduction and transfer of TR NO_X Annual allowances based on the information as adjusted under § 97.428 of this chapter.

(vi) The finalization of control period emissions data, including retroactive adjustment based on audit.

(vii) The approval or disapproval of a petition under § 97.435 of this chapter.

(viii) The approval or disapproval of a TR opt-in application, the approval or disapproval of a request to withdraw, the decision on allocation of TR NO_X Annual allowances, and the decision on the deduction of TR NO_X Annual allowances under §§ 97.441 through 97.444.

(14) Under subpart BBBBB of part 97 of this chapter, (i) The decision on allocation of TR NO_X Ozone Season

allowances under § 97.511(a)(2) and (b) of this chapter.

(ii) The decision on the transfer of TR NO_X Ozone Season allowances under § 97.523 of this chapter.

(iii) The decision on the deduction of TR NO_X Ozone Season allowances under §§ 97.524 and 97.525 of this chapter.

(iv) The correction of an error in an Allowance Management System account under § 97.527 of this chapter.

(iv) The adjustment of information in a submission and the decision on the deduction and transfer of TR NO_X Ozone Season allowances based on the information as adjusted under § 97.528 of this chapter.

(vi) The finalization of control period emissions data, including retroactive adjustment based on audit.

(vii) The approval or disapproval of a petition under § 97.535 of this chapter.

(viii) The approval or disapproval of a TR opt-in application, the approval or disapproval of a request to withdraw, the decision on allocation of TR NO_X Ozone Season allowances, and the decision on the deduction of TR NO_X Ozone Season allowances under §§ 97.541 through 97.544.

(15) Under subpart CCCCC of part 97 of this chapter,

(i) The decision on allocation of TR SO_2 Group 1 allowances under § 97.611(a)(2) and (b) of this chapter.

(ii) The decision on the transfer of TR SO_2 Group 1 allowances under § 97.623 of this chapter.

(iii) The decision on the deduction of TR SO_2 Group 1 allowances under §§ 97.624 and 97.625 of this chapter.

(iv) The correction of an error in an Allowance Management System account under § 97.627 of this chapter.

(iv) The adjustment of information in a submission and the decision on the deduction and transfer of TR SO_2 Group 1 allowances based on the information as adjusted under § 97.628 of this chapter.

(vi) The finalization of control period emissions data, including retroactive adjustment based on audit.

(vii) The approval or disapproval of a petition under § 97.635 of this chapter.

(viii) The approval or disapproval of a TR opt-in application, the approval or disapproval of a request to withdraw, the decision on allocation of TR SO_2 Group 1 allowances, and the decision on the deduction of TR SO_2 Group 1 allowances under §§ 97.641 through 97.644.

(16) Under subpart DDDDD of part 97 of this chapter,

(i) The decision on allocation of TR SO_2 Group 2 allowances under § 97.711(a)(2) and (b) of this chapter.

(ii) The decision on the transfer of TR SO_2 Group 1 allowances under § 97.723 of this chapter.

(iii) The decision on the deduction of TR SO_2 Group 1 allowances under §§ 97.724 and 97.725 of this chapter.

(iv) The correction of an error in an Allowance Management System account under § 97.727 of this chapter.

(iv) The adjustment of information in a submission and the decision on the deduction and transfer of TR SO_2 Group 1 allowances based on the information as adjusted under § 97.728 of this chapter.

(vi) The finalization of control period emissions data, including retroactive adjustment based on audit.

(vii) The approval or disapproval of a petition under § 97.735 of this chapter.

(viii) The approval or disapproval of a TR opt-in application, the approval or disapproval of a request to withdraw, the decision on allocation of TR SO_2 Group 2 allowances, and the decision on the deduction of TR SO_2 Group 2 allowances under §§ 97.741 through 97.744.

* * * * *

§ 78.2 [Amended]

31. Section 78.2 is revised to read as follows:

§ 78.2 General.

(a) *Definitions.* (1) The terms used in this subpart with regard to a decision of the Administrator that is appealed under this section shall have the meaning as set forth in the regulations under which the Administrator made such decision and as set forth in paragraph (a)(2) of this section.

(2) *Interested person* means, with regard to a decision of the Administrator, any person who submitted comments, or testified at a public hearing, pursuant to an opportunity for comment provided by the Administrator as part of the process of making such decision, who submitted objections pursuant to an opportunity for objections provided by the Administrator as part of the process of making such decision, or who submitted his or her name to the Administrator to be placed on a list of persons interested in such decision. The Administrator may update the list of interested persons from time to time by requesting additional written indication of continued interest from the persons listed and may delete from the list the name of any person failing to respond as requested.

(b) *Availability of information.* The availability to the public of information provided to, or otherwise obtained by, the Administrator under this subpart shall be governed by part 2 of this chapter.

(c) *Computation of time.* (1) In computing any period of time prescribed or allowed under this part, except as otherwise provided, the day of the event from which the period begins to run shall not be included, and Saturdays, Sundays, and federal holidays shall be included. When the period ends on a Saturday, Sunday, or Federal holiday, the stated period shall be extended to include the next business day.

(2) Where a document is served by first class mail or commercial delivery service, but not by overnight or same-day delivery, 5 days shall be added to the time prescribed or allowed under this part for the filing of a responsive document or for otherwise responding.

§ 78.3 [Amended]

32. Section 78.3 is amended by:

a. In paragraphs (a)(1)(iii), (a)(3)(ii), (a)(4)(ii), (a)(5)(ii), (a)(6)(ii), (a)(7)(ii), (a)(8)(ii), and (a)(9)(ii), adding, after the word "person", the words "with regard to the decision".

b. Adding paragraph (a)(10);

c. In paragraph (b)(3)(i), removing the words "paragraph (a)(1) and (2)" and adding, in their place, the words "paragraph (a)(1), (2), and (10)"; and

d. Adding paragraph (d)(11) to read as follows:

§ 78.3 Petition for administrative review and request or evidentiary hearing.

(a) * * *

(10) The following persons may petition for administrative review of a decision of the Administrator that is made under subparts AAAAA, BBBBB, CCCCC, and DDDDD of part 97 of this chapter:

(i) The designated representative for a unit or source, or the authorized account representative for any Allowance Management System account, covered by the decision; or

(ii) Any interested person with regard to the decision.

* * * * *

(d) * * *

(11) Any provision or requirement of subparts AAAAA, BBBBB, CCCCC, or DDDDD of part 97 of this chapter, including the standard requirements under § 97.406, § 97.506, § 97.606, or § 97.706 of this chapter and any emission monitoring or reporting requirements.

§ 78.4 [Amended]

33. Section 78.4 is amended by:

a. Revising paragraph (a) by:

i. Removing the first, second, third, fourth, fifth, and last sentences;

ii. In the sixth and seventh sentences, removing the words "interest in" and adding, in their place, the words "ownership interest with respect to"; and

iii. Redesignating the paragraph as paragraph (a)(1)(iii); and

b. Adding paragraphs (a)(1) introductory text, (a)(1)(i), (a)(1)(ii) and (a)(2) to read as follows:

§ 78.4 Filings.

(a)(1) All original filings made under this part shall be signed by the person making the filing or by an attorney or authorized representative, in accordance with the following requirements:

(i) Any filings on behalf of owners and operators of a affected unit or affected source, TR NO_X Annual unit or TR NO_X Annual source, TR NO_X Ozone Season unit or TR NO_X Ozone Season source, TR SO_2 Group 1 unit or TR SO_2 Group 1 source, TR SO_2 Group 2 unit or TR SO_2 Group 2 source, or a unit for which a TR opt-in application is submitted and not withdrawn shall be signed by the designated representative. Any filing on behalf of persons with an ownership interest with respect to allowances, TR NO_X Annual allowances, TR NO_X Ozone Season allowances, TR SO_2 Group 1 allowances, or TR SO_2 Group 2 allowances in a general account shall be signed by the authorized account representative.

(ii) Any filings on behalf of owners and operators of a NO_X Budget unit or NO_X Budget source shall be signed by the NO_X authorized account representative. Any filing on behalf of persons with an ownership interest with respect to NO_X allowances in a general account shall be signed by the NO_X authorized account representative.

* * * * *

(2) The name, address, e-mail address (if any), telephone number, and facsimile number (if any) of the person making the filing shall be provided with the filing.

* * * * *

PART 97—[AMENDED]

34. The authority citation for part 97 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7426, 7601, and 7651, *et seq.*

35. Part 97 is amended by adding subpart AAAAA to read as follows:

Subpart AAAAA TR NO_X Annual Trading Program

Sec.

Subpart AAAAA—TR NO_X Annual Trading Program

§ 97.401 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Transport Rule (TR) NO_X Annual Trading Program, under section 110 of the Clean Air Act and § 52.37(a) of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

§ 97.402 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor) of the United States Environmental Protection Agency, the Administrator's duly authorized representative under this subpart.

Allocate or allocation means, with regard to TR NO_X Annual allowances, the determination by the Administrator of the amount of such TR NO_X Annual allowances to be initially credited to a TR NO_X Annual source or a new unit set-aside.

Allowable NO_X emission rate means, with regard to a unit, the NO_X emission rate limit that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, deductions, and transfers of TR NO_X Annual allowances under the TR NO_X Annual Trading Program. Such allowances are allocated, held, deducted, or transferred only as whole allowances. The Allowance Management System is a component of the CAMD Business System, which is the system used by the Administrator to handle TR NO_X Annual allowances and data related to NO_X emissions.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, holding, transfer, or deduction of TR NO_X Annual allowances.

Allowance transfer deadline means, for a control period, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR NO_X Annual allowance transfer must be submitted for recordation in a TR NO_X

Annual source's compliance account in order to be available for use in complying with the source's TR NO_X Annual emissions limitation for such control period in accordance with § 97.424.

Alternate designated representative means, for a TR NO_X Annual source and each TR NO_X Annual unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the TR NO_X Annual Trading Program. If the TR NO_X Annual source is also subject to the Acid Rain Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative as defined in § 72.2 of this chapter, § 97.502, § 97.602, or § 97.702 respectively.

Authorized account representative means, with regard to a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of TR NO_X Annual allowances held in the general account and, with regard to a TR NO_X Annual source's compliance account, the designated representative of the source.

Automated data acquisition and handling system or DAHS means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, 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 this subpart.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

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.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president or the corporation in charge of a principal business function or any other person who performs similar policy or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, et seq.

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during 1990 or any year thereafter.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine—

(1) Operating as part of a cogeneration system; and

(2) Producing during the later of 1990 or the 12-month period starting on the date that the unit first produces electricity and during each calendar year after the later of 1990 or the calendar year in which the unit first produces electricity—

(i) For a topping-cycle unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel, except biomass if the unit is a boiler; and

(4) Provided that, if a topping-cycle unit is operated as part of a cogeneration system during a calendar year and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) of this definition, the topping-cycle unit shall be deemed to meet such requirement during that calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, 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; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) 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 § 97.405.

(i) For a unit that is a TR NO_X Annual unit under § 97.404 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a TR NO_X Annual unit under § 97.404 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 97.405, for a unit that is not a TR NO_X Annual unit under § 97.404 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in introductory text of paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a TR NO_X Annual unit under § 97.404.

(i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Commence operation means, with regard to a unit:

(1) To have begun any mechanical, chemical, or electronic process, including start-up of the unit's combustion chamber.

(2) For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(3) For a unit that is replaced by a unit at the same source after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the replaced unit's date of commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a TR NO_X Annual source under this subpart, in which any TR NO_X Annual allowance allocations for the TR NO_X Annual units at the source are recorded and in which are held any TR NO_X Annual allowances available for use for a control period in complying with the source's TR NO_X Annual emissions limitation in accordance with § 97.424 and the TR NO_X Annual assurance provisions in accordance with § 97.425.

Continuous emission monitoring system or CEMS means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of NO_X emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 or CO_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§ 97.430 through 97.435. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A NO_X concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X emissions, in parts per million (ppm);

(3) A NO_X emission rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2, and NO_X emission rate, in pounds per million British thermal units (lb/mmBtu);

(4) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(5) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(6) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period starting January 1 of a calendar year, except as provided in § 97.406(c)(3), and ending on December 31 of the same year, inclusive.

Designated representative means, for a TR NO_X Annual source and each TR NO_X Annual unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the TR NO_X Annual Trading Program. If the TR NO_X Annual source is also subject to the Acid Rain Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in § 72.2 of this chapter, § 97.502, § 97.602, or § 97.702 respectively.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart.

Excess emissions means any ton of NO_X emitted from the TR NO_X Annual units at a TR NO_X Annual source during a control period that exceeds the TR NO_X Annual emissions limitation for the source.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying §§ 97.404(b)(2)(i)(B), 97.404(b)(2)(ii)(B), and 97.404(b)(2)(iii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 1990 or any calendar year thereafter.

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a unit for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

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 generated by 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 no less 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 maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

Newly affected TR NO_X Annual unit means a unit that was not a TR NO_X Annual unit when it began operating but that thereafter becomes a TR NO_X Annual unit.

Operate or operation means, with regard to a unit, to combust fuel.

Operator means any person who operates, controls, or supervises a TR NO_X Annual unit or a TR NO_X Annual source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means, with regard to a TR NO_X Annual source or a TR NO_X Annual unit at a source respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a TR NO_X Annual unit at the source or the TR NO_X Annual unit;

(2) Any holder of a leasehold interest in a TR NO_X Annual unit at the source or the TR NO_X Annual unit, provided that, 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) on the revenues or income from such TR NO_X Annual unit;

(3) Any purchaser of power from a TR NO_X Annual unit at the source or the TR NO_X Annual unit under a life-of-the-unit, firm power contractual arrangement;

(4) Provided that, for purposes of applying the TR NO_X Annual assurance provisions in §§ 97.406(c)(2) and 97.425, if one or more owners (as defined in paragraphs (1) through (3) of this definition) of one or more TR NO_X Annual units in a State are wholly owned by another, common owner, all such owners shall be treated collectively as a single owner in the State.

Owner's assurance level means:

(1) With regard to a State and control period for which the State assurance level is exceeded as described in § 97.406(c)(2)(iii)(A) and not as described in § 97.406(c)(2)(iii)(B), the owner's share of the State NO_X Annual trading budget with the one-year variability limit for the State for such control period; or

(2) With regard to a State and control period for which the State assurance level is exceeded as described in § 97.406(c)(2)(iii)(B), the owner's share of the State NO_X Annual trading budget with the three-year variability limit for the State for such control period.

Owner's share means:

(1) With regard to a total amount of NO_X emissions from all TR NO_X Annual units in a State during a control period, the total tonnage of NO_X emissions during such control period from all of the owner's TR NO_X Annual units in the State;

(2) With regard to a State NO_X Annual trading budget with a one-year variability limit for a control period, the amount (rounded to the nearest allowance) equal to the total amount of TR NO_X Annual allowances allocated for such control period to all of the owner's TR NO_X Annual units in the State, multiplied by the sum of the State NO_X Annual trading budget under § 97.410(a) and the State's one-year variability limit under § 97.410(b) and divided by such State NO_X Annual trading budget;

(3) With regard to a State NO_X Annual trading budget with a three-year variability limit for a control period, the amount (rounded to the nearest allowance) equal to the total amount of TR NO_X Annual allowances allocated for such control period to all of the owner's TR NO_X Annual units in the State, multiplied by the sum of the State NO_X Annual trading budget under § 97.410(a) and the State's three-year variability limit under § 97.410(b) and divided by such State NO_X Annual trading budget;

(4) Provided that, in the case of a unit with more than one owner, the amount of tonnage of NO_X emissions and of TR NO_X Annual allowances allocated for a control period, with regard to such unit, used in determining each owner's share

shall be the amount (rounded to the nearest ton and the nearest allowance) equal to the unit's NO_X emissions and allocation of such allowances, respectively, for such control period multiplied by the percentage of ownership in the unit that the owner's legal, equitable, leasehold, or contractual reservation or entitlement in the unit comprises as of December 31 of such control period;

(5) Provided that, where two or more units emit through a common stack that is the monitoring location from which NO_X mass emissions are reported for a control period for a year, the amount of tonnage of each unit's NO_X emissions used in determining each owner's share for such control period shall be:

(i) The amount (rounded to the nearest ton) of NO_X emissions reported at the common stack multiplied by the quotient of such unit's heat input for such control period divided by the total heat input reported from the common stack for such control period;

(ii) An amount determined in accordance with a methodology that the Administrator determines is consistent with the purposes of this definition and whose adverse effect (if any) the Administrator determines will be *de minimis*; or

(iii) An amount approved by the Administrator in response to a petition for an alternative requirement submitted in accordance with § 97.435; and

(6) Provided that, in the case of a unit that operates during, but is allocated no TR NO_X Annual allowances for, a control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of TR NO_X Annual allowances for such control period equal to the lesser of—

(i) The unit's allowable NO_X emission rate (in lb per MWe) applicable to such control period, multiplied by a capacity factor of 0.84 (if the unit is a coal-fired boiler), 0.15 (if the unit is a simple combustion turbine), or 0.66 (if the unit is a combined cycle turbine), multiplied by the unit's maximum hourly load as reported in accordance with this subpart and by 8,760 hours/control period, and divided by 2,000 lb/ton; or

(ii) For a unit listed in appendix A to this subpart, the sum of the unit's NO_X emissions in the control period in the last three years during which the unit operated during the control period, divided by three.

Permanently retired means, with regard to a unit, a unit that is unavailable for service and that the unit's owners and operators do not expect to return to service in the future.

Permitting authority means "permitting authority" as defined in §§ 70.2 and 71.2 of this chapter.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to TR NO_X Annual allowances, the moving of TR NO_X Annual allowances by the Administrator into, out of, or between Allowance Management System accounts, 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 § 75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

(1) For a topping-cycle unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle unit, the use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a TR NO_X Annual allowance, the unique identification number assigned to each TR NO_X Annual allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a "solid waste incineration unit" as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of "major source," "stationary source," or "source" as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States or the District of Columbia that is subject to the TR NO_X Annual Trading Program pursuant to § 52.37(a) of this chapter.

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;

(4) Provided that compliance with any "submission" or "service" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Topping-cycle unit means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means total energy of all forms supplied to a unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

$$LHV = HHV - 10.55(W + 9H)$$

Where:

LHV = lower heating value of the form of energy in Btu/lb,

HHV = higher heating value of the form of energy in Btu/lb,

W = weight % of moisture in the form of energy, and

H = weight % of hydrogen in the form of energy.

Total energy output means the sum of useful power and useful thermal energy produced by the unit.

TR NO_X Annual allowance means a limited authorization issued and allocated by the Administrator under this subpart to emit one ton of NO_X during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the TR NO_X Annual Program.

TR NO_X Annual allowance deduction or deduct TR NO_X Annual allowances means the permanent withdrawal of TR NO_X Annual allowances by the Administrator from a compliance account, *e.g.*, in order to account for compliance with the TR NO_X Annual emissions limitation or assurance provisions.

TR NO_X Annual allowances held or hold TR NO_X Annual allowances means the TR NO_X Annual allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, TR NO_X Annual allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, TR NO_X Annual allowance transfer in accordance with this subpart.

TR NO_X Annual Trading Program means a multi-state NO_X air pollution control and emission reduction program established by the Administrator in accordance with this subpart and 52.37(a) of this chapter, as a means of mitigating interstate transport of fine particulates and NO_X.

TR NO_X Annual emissions limitation means, for a TR NO_X Annual source, the tonnage of NO_X emissions authorized in a control period by the TR NO_X Annual allowances available for deduction for the source under § 97.424(a) for such control period.

TR NO_X Annual source means a source that includes one or more TR NO_X Annual units.

TR NO_X Annual unit means a unit that is subject to the TR NO_X Annual Trading Program under § 97.404.

TR NO_X Ozone Season Trading Program means a multi-state NO_X air pollution control and emission reduction program established by the Administrator in accordance with subpart BBBBB of this part and 52.37(b) of this chapter, as a means of mitigating interstate transport of ozone and NO_X.

TR SO_2 Group 1 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established by the Administrator in accordance with subpart CCCCC of this part and 52.38(b) of this chapter, as a means of mitigating interstate transport of fine particulates and SO_2.

TR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established by the Administrator in accordance with subpart DDDDD of this part and 52.38(c) of this chapter, as a means of mitigating interstate transport of fine particulates and SO_2.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or hour of unit operation means an hour in which a unit combusts any fuel.

Useful power means electricity or mechanical energy that a unit makes available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (*e.g.,* space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.,* in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 97.403 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit
CO_2—carbon dioxide
H_2O—water
hr—hour
kW—kilowatt electrical
kWh—kilowatt hour
lb—pound
mmBtu—million Btu
MWe—megawatt electrical
MWh—megawatt hour
NO_X—nitrogen oxides
O_2—oxygen
ppm—parts per million
scfh—standard cubic feet per hour
SO_2—sulfur dioxide
yr—year

§ 97.404 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State shall be TR NO_X Annual units, and any source that includes one or more such units shall be a TR NO_X Annual source, subject to the requirements of this subpart: Any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a TR NO_X Annual unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a TR NO_X Annual unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State that otherwise is a TR NO_X Annual unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i), (b)(2)(i), or (b)(2)(ii) of this section shall not be a TR NO_X Annual unit:

(1)(i) Any unit:

(A) Qualifying as a cogeneration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If a unit qualifies as a cogeneration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (b)(1)(i) of this section for at least one calendar year, but subsequently no longer meets such qualification and requirements, the unit shall become a TR NO_X Annual unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section.

(2)(i) Any unit commencing operation before January 1, 1985:

(A) Qualifying as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit; and

(B) With an average annual fuel consumption of fossil fuel for 1985–1987 less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years after 1990 less than 20 percent (on a Btu basis).

(ii) Any unit commencing operation on or after January 1, 1985:

(A) Qualifying as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit; and

(B) With an average annual fuel consumption of fossil fuel for the first 3 calendar years of operation less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years after 1990 less than 20 percent (on a Btu basis).

(iii) If a unit qualifies as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraph (b)(2)(i) or (ii) of this section for at least 3 consecutive calendar years, but subsequently no longer meets such qualification and requirements, the unit shall become a TR NO_X Annual unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 1990 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more.

(c) A certifying official of an owner or operator of any unit or other equipment may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR NO_X Annual Trading Program to the unit or other equipment.

(1) *Petition content.* The petition shall be in writing and include the identification of the unit or other equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: "I am authorized to make this submission on behalf of the owners and operators of the unit or other equipment 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) *Response.* The Administrator will issue a written response to the petition and may request supplemental information determined by the Administrator to be relevant to such petition. The Administrator's determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR NO_X Annual Trading Program to the unit or other equipment shall be binding on any permitting authority unless the Administrator determines that the petition or other documents or information provided in connection with the petition contained significant, relevant errors or omissions.

§ 97.405 Retired unit exemption.

(a)(1) Any TR NO_X Annual unit that is permanently retired and is not a TR NO_X Annual opt-in unit shall be exempt from § 97.406(b) and (c)(1), § 97.424, and §§ 97.430 through 97.435.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the TR NO_X Annual unit is permanently retired. Within 30 days of the unit's permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of 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 before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the TR NO_X Annual 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 exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

§ 97.406 Standard requirements.

(a) *Designated representative requirements.* The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§ 97.413 through 97.418.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.430 through 97.435.

(2) The emissions data determined in accordance with §§ 97.430 through 97.435 shall be used to calculate allocations of TR NO_X Annual allowances under §§ 97.411(a)(2) and (b) and 97.412 and to determine compliance with the TR NO_X Annual emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) *NO_X emissions requirements.* (1) TR NO_X Annual emissions limitation. (i) As of the allowance transfer deadline for a control period, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall hold, in the source's compliance account, TR NO_X Annual allowances available for deduction for such control period under § 97.424(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Annual units at the source.

(ii) If a TR NO_X Annual source emits NO_X during any control period in excess of the TR NO_X Annual emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR NO_X Annual unit at the source shall hold the TR NO_X Annual allowances required for deduction under § 97.424(d) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act; and

(B) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) TR NO_X Annual assurance provisions. (i) If the total amount of NO_X emissions from all TR NO_X Annual units in a State during a control period in 2014 or any year thereafter exceeds the State assurance level as described in paragraph (c)(2)(iii) of this section, then each owner whose share of such NO_X emissions during such control period exceeds the owner's assurance level for the State and such control period shall hold, in a compliance account designated by the owner in accordance with § 97.425(b)(4)(ii), TR NO_X Annual allowances available for deduction for such control period under § 97.425(a) in an amount equal to the product, as determined by the Administrator in accordance with § 97.425(b), of multiplying—

(A) The quotient (rounded to the nearest whole number) of the amount by which the owner's share of such NO_X emissions exceeds the owner's assurance level divided by the sum of the amounts, determined for all such owners, by which each owner's share of such NO_X emissions exceeds that owner's assurance level; and

(B) The amount by which total NO_X emissions for all TR NO_X Annual units in the State for such control period exceed the State assurance level as determined in accordance with paragraph (c)(2)(iii) of this section.

(ii) The owner shall hold the TR NO_X Annual allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) The total amount of NO_X emissions from all TR NO_X Annual units in a State during a control period in 2014 or any year thereafter exceeds the State assurance level:

(A) If such total amount of NO_X emissions exceeds the sum, for such control period, of the State NO_X Annual trading budget and the State's one-year variability limit under § 97.410(b); or

(B) If, with regard to a control period in 2016 or any year thereafter, the sum, divided by three, of such total amount of NO_X emissions and the total amounts of NO_X emissions from all TR NO_X Annual units in the State during the control periods in the immediately preceding two years exceeds the sum, for such control period, of the State NO_X Annual trading budget and the State's three-year variability limit under § 97.410(b);

(C) Provided that the amount by which such total amount of NO_X emissions exceeds the State assurance level shall be the greater of the amounts of the exceedance calculated under paragraph (c)(2)(iii)(A) of this section and under paragraph (c)(2)(iii)(B) of this section.

(iv) It shall not be a violation of this subpart or of the Clean Air Act if the total amount of NO_X emissions from all TR NO_X Annual units in a State during a control period exceeds the State assurance level or if an owner's share of total NO_X emissions from the TR NO_X Annual units in a State during a control period exceeds the owner's assurance level.

(v) To the extent an owner fails to hold TR NO_X Annual allowances for a control period in accordance with paragraphs (c)(2)(i) and (ii) of this section,

(A) The owner shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR NO_X Annual allowance that the owner fails to hold for a control period in accordance with paragraphs (c)(2)(i) and (ii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) *Compliance periods.* A TR NO_X Annual unit shall be subject to the requirements:

(i) Under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2012 or the deadline for meeting the unit's monitor certification requirements under § 97.430(b) and for each control period thereafter; and

(ii) Under paragraph (c)(2) of this section for the control period starting on the later of January 1, 2014 or the deadline for meeting the unit's monitor certification requirements under § 97.430(b) and for each control period thereafter.

(4) *Vintage of deducted allowances.* A TR NO_X Annual allowance shall not be deducted, for compliance with the requirements under paragraphs (c)(1) and (2) of this section, for a control period in a calendar year before the year for which the TR NO_X Annual allowance was allocated.

(5) *Allowance Management System requirements.* Each TR NO_X Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) *Limited authorization.* (i) A TR NO_X Annual allowance is a limited authorization to emit one ton of NO_X in accordance with the TR NO_X Annual Trading Program.

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) *Property right.* A TR NO_X Annual allowance does not constitute a property right.

(d) *Title V Permit requirements.* (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_X Annual allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report NO_X emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.430 through 97.435 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) *Additional recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 97.416 for the designated representative for the source and each TR NO_X Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; 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 certificate of representation under § 97.416 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NO_X Annual Trading Program, including any monitoring plans and monitoring system certification and recertification applications.

(2) The designated representative of a TR NO_X Annual source and each TR NO_X Annual unit at the source shall make all submissions required under the TR NO_X Annual Trading Program, including any submissions required for compliance with the TR NO_X Annual assurance provisions. This requirement does not change, create an exemption from, or or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) *Liability*. (1) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual source or the designated representative of a TR NO_X Annual source shall also apply to the owners and operators of such source and of the TR NO_X Annual units at the source.

(2) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual unit or the designated representative of a TR NO_X Annual unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities*. No provision of the TR NO_X Annual Trading Program or exemption under § 97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_X Annual source or TR NO_X Annual unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 97.407 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the TR NO_X Annual 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 TR NO_X Annual 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 TR NO_X Annual Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 97.408 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the TR NO_X Annual Trading Program are set forth in part 78 of this chapter.

§ 97.409 [Reserved]

§ 97.410 State NO_X Annual trading budgets, new-unit set-asides, and variability limits.

(a) The State NO_X Annual trading budgets and new-unit set-asides for allocations of TR NO_X Annual allowances for the control periods in 2012 and thereafter are as follows:

State	NO_X annual trading budget (tons) *	New-unit set-aside (tons)
	For 2012 and thereafter	For 2012 and thereafter
Alabama	69,169	2,075
Connecticut	2,775	83
Delaware	6,206	186
District of Columbia	170	5
Florida	120,001	3,600
Georgia	73,801	2,214
Illinois	56,040	1,681
Indiana	115,687	3,471
Iowa	46,068	1,382
Kansas	51,321	1,540
Kentucky	74,117	2,224
Louisiana	43,946	1,318
Maryland	17,044	511
Massachusetts	5,960	179
Michigan	64,932	1,948
Minnesota	41,322	1,240
Missouri	57,681	1,730
Nebraska	43,228	1,297
New Jersey	11,826	355
New York	23,341	700
North Carolina	51,800	1,554
Ohio	97,313	2,919
Pennsylvania	113,903	3,417
South Carolina	33,882	1,016
Tennessee	28,362	851
Virginia	29,581	887
West Virginia	51,990	1,560
Wisconsin	44,846	1,345

State	NO_X annual trading budget (tons) *	New-unit set-aside (tons)
	For 2012 and thereafter	For 2012 and thereafter
Total	1,376,312	41,288

* Without variability limits.

(b) The States' one-year and three-year variability limits for the State NO_X Annual trading budgets for the control periods in 2014 and thereafter are as follows:

State	One-year variability limits	Three-year variability limits
	2014 and thereafter (tons)	2016 and thereafter (tons)
Alabama	6,917	3,993
Connecticut	5,000	2,887
Delaware	5,000	2,887
District of Columbia	5,000	2,887
Florida	12,000	6,928
Georgia	7,380	4,261
Illinois	5,604	3,235
Indiana	11,569	6,679
Iowa	5,000	2,887
Kansas	5,132	2,963
Kentucky	7,412	4,279
Louisiana	5,000	2,887
Maryland	5,000	2,887
Massachusetts	5,000	2,887
Michigan	6,493	3,749
Minnesota	5,000	2,887
Missouri	5,768	3,330
Nebraska	5,000	2,887
New Jersey	5,000	2,887
New York	5,000	2,887
North Carolina	5,180	2,991
Ohio	9,731	5,618
Pennsylvania	11,390	6,576
South Carolina	5,000	2,887
Tennessee	5,000	2,887
Virginia	5,000	2,887
West Virginia	5,199	3,002
Wisconsin	5,000	2,887

§ 97.411 Timing requirements for TR NO_X Annual allowance allocations.

(a) *Existing units.* (1) TR NO_X Annual allowances are allocated, for the control periods in 2012 and each year thereafter, as set forth in appendix A to this subpart. Listing a unit in such appendix does not constitute a determination that the unit is a TR NO_X Annual unit, and not listing a unit in such appendix does not constitute a determination that the unit is not a TR NO_X Annual unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit listed in appendix A to this subpart as being allocated TR NO_X Annual allowances does not operate, starting after 2011, during the control period in three consecutive years, such unit will not be allocated the TR NO_X Annual allowances set forth in appendix A to this subpart for the unit for the control periods in the seventh year after the first such year and in each year after that seventh year. All TR NO_X Annual allowances that would otherwise have been allocated to such unit will be allocated to the new unit set-aside for the respective years involved. If such unit resumes operation, the Administrator will allocate TR NO_X Annual allowances to the unit in accordance with paragraph (b) of this section.

(b) *New units.* (1) By July 1, 2012 and July 1 of each year thereafter, the Administrator will calculate the TR NO_X Annual allowance allocation for each TR NO_X Annual unit, in accordance with § 97.412, for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of availability of the results of the calculations.

(2) For each notice of data availability required in paragraph (b)(1) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations are in accordance with § 97.412 and §§ 97.406(b)(2) and 97.430 through 97.435.

(ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By September 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.

(c) *Units that are not TR NO_X Annual units.* For each control period in 2012 and thereafter, if the Administrator determines that TR NO_X Annual allowances were allocated under paragraph (a) of this section for the control period to a recipient that is not actually a TR NO_X Annual unit under § 97.404 as of January 1, 2012 or whose deadline for meeting monitor certification requirements under § 97.430(b)(1) and (2) is after January 1, 2012 or if the Administrator determines that TR NO_X Annual allowances were allocated under paragraph (b) of this section and § 97.412 for the control period to a recipient that is not actually a TR NO_X Annual unit under § 97.404 as of January 1 of the control period, then the Administrator will notify the designated representative and will act in accordance with the following procedures:

(1) Except as provided in paragraph (c)(2) or (3) of this section, the Administrator will not record such TR NO_X Annual allowances under § 97.421.

(2) If the Administrator already recorded such TR NO_X Annual allowances under § 97.421 and if the Administrator makes such determination before making deductions for the source that includes such recipient under § 97.424(b) for such control period, then the Administrator will deduct from the account in which such TR NO_X Annual allowances were recorded an amount of TR NO_X Annual allowances allocated for the same or a prior control period equal to the amount of such already recorded TR NO_X Annual allowances. The authorized account representative shall ensure that there are sufficient TR NO_X Annual allowances in such account for completion of the deduction.

(3) If the Administrator already recorded such TR NO_X Annual allowances under § 97.421 and if the Administrator makes such determination after making deductions for the source that includes such recipient under § 97.424(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded TR NO_X Annual allowances.

(4) The Administrator will transfer the TR NO_X Annual allowances that are not recorded, or that are deducted, in accordance with paragraphs (c)(1) and (2) of this section to the new unit set-aside, for the State in which such recipient is located, for the control period in the year of such transfer if the notice required in paragraph (b)(1) of this section for the control period in that year has not been promulgated or, if such notice has been promulgated, in the next year.

§ 97.412 TR NO_X Annual allowance allocations for new units.

(a) For each control period in 2012 and thereafter, the Administrator will allocate, in accordance with the following procedures, TR NO_X Annual allowances to TR NO_X Annual units in a State that are not listed in appendix A to this subpart, to TR NO_X Annual units that are so listed and whose allocation of NO_X Annual allowances for such control period is covered by § 97.411(c)(1) or (2), and to TR NO_X Annual units that are so listed and, pursuant to § 97.411(a)(2), are not allocated TR NO_X Annual allowances for such control period but operate during the immediately preceding control period:

(1) The Administrator will establish a separate new unit set-aside for each State for each control period in a given year. Each new unit set-aside will be allocated TR NO_X Annual allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.410(a). Each new unit set-aside will be allocated additional TR NO_X Annual allowances in accordance with § 97.411(a)(2) and (c)(4).

(2) The designated representative of such TR NO_X Annual unit may submit to the Administrator a request, in a format prescribed by the Administrator, to be allocated TR NO_X Annual allowances for a control period, starting with the later of the control period in 2012, the first control period after the control period in which the TR NO_X Annual unit commences commercial operation (for a unit not listed in appendix A to this subpart), or the first control period after the control period in which the unit resumes operation (for a unit listed in appendix A of this subpart) and for each subsequent control period.

(i) The request must be submitted on or before May 1 of the first control period for which TR NO_X Annual allowances are sought and after the date on which the TR NO_X Annual unit commences commercial operation (for a unit not listed in appendix A of this subpart) or on which the unit resumes operation (for a unit listed in appendix A of this subpart).

(ii) For each control period for which an allocation is sought, the request must be for TR NO_X Annual allowances in an amount equal to the unit's total tons of NO_X emissions during the immediately preceding control period.

(3) The Administrator will review each TR NO_X Annual allowance allocation request under paragraph (a)(2) of this section and will accept the request only if it meets the requirements of paragraph (a)(2) of this section. The Administrator will allocate TR NO_X Annual allowances for each control period pursuant to an accepted request as follows:

(i) After May 1 of such control period, the Administrator will determine the sum of the TR NO_X Annual allowances requested in all accepted allowance allocation requests for such control period.

(ii) If the amount of TR NO_X Annual allowances in the new unit set-aside for such control period is greater than or equal to the sum under paragraph (a)(3)(i) of this section, then the Administrator will allocate the amount of TR NO_X Annual allowances requested to each TR NO_X Annual unit covered by an accepted allowance allocation request.

(iii) If the amount of TR NO_X Annual allowances in the new unit set-aside for such control period is less than the sum under paragraph (a)(3)(i) of this section, then the Administrator will allocate to each TR NO_X Annual unit covered by an accepted allowance allocation request the amount of the TR NO_X Annual allowances requested, multiplied by the amount of TR NO_X Annual allowances in the new unit set-aside for such control period, divided by the sum determined under paragraph (a)(3)(i) of this section, and rounded to the nearest allowance.

(iv) The Administrator will notify, through the promulgation of the notices of data availability described in § 97.411(b), each designated representative that submitted an allowance allocation request of the amount of TR NO_X Annual allowances (if any) allocated for such control period to the TR NO_X Annual unit covered by the request.

(b) If, after completion of the procedures under paragraph (a)(4) of this section for a control period, any unallocated TR NO_X Annual allowances remain in the new unit set-aside under paragraph (a) of this section for a State for such control period, the Administrator will allocate to each TR

NO_X Annual unit that is in the State, is listed in appendix A to this subpart, and continues to be allocated TR NO_X Annual allowances for such control period in accordance with § 97.411(a)(2), an amount of TR NO_X Annual allowances equal to the following: The total amount of such remaining unallocated TR NO_X Annual allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.411(a) for such control period, divided by the remainder of the amount of tons in the applicable State NO_X Annual trading budget minus the amount of tons in such new unit set-aside, and rounded to the nearest allowance.

§ 97.413 Authorization of designated representative and alternate designated representative.

(a) Except as provided under § 97.415, each TR NO_X Annual source, including all TR NO_X Annual units at the source, shall have one and only one designated representative, with regard to all matters under the TR NO_X Annual Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR NO_X Annual units at the source and shall act in accordance with the certification statement in § 97.416(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.416:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each TR NO_X Annual unit at the source in all matters pertaining to the TR NO_X Annual Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each TR NO_X Annual unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under § 97.415, each TR NO_X Annual source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR NO_X Annual units at the source and shall act in accordance with the certification statement in § 97.416(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.416:

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each TR NO_X Annual unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit.

(c) Except in this section, § 97.402, and §§ 97.414 through 97.418, whenever the term "designated representative" is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 97.414 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under § 97.418 concerning delegation of authority to make submissions, each submission under the TR NO_X Annual Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each TR NO_X Annual source and TR NO_X Annual unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or 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."

(b) The Administrator will accept or act on a submission made for a TR NO_X Annual source or a TR NO_X Annual unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 97.418.

§ 97.415 Changing designated representative and alternate designated representative; changes in owners and operators.

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.416. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the TR NO_X Annual source and the TR NO_X Annual units at the source.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.416. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the TR NO_X Annual source and the TR NO_X Annual units at the source.

(c) *Changes in owners and operators.* (1) In the event an owner or operator of a TR NO_X Annual source or a TR NO_X Annual unit is not included in the list of owners and operators in the certificate of representation under § 97.416, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a TR NO_X Annual source or a TR NO_X Annual unit, including the addition of a new

owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under § 97.416 amending the list of owners and operators to include the change.

§ 97.416 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the TR NO_X Annual source, and each TR NO_X Annual unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe rounded to the nearest tenth) of each generator served by each such unit, and actual or projected date of commencement of commercial operation.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the TR NO_X Annual source and of each TR NO_X Annual unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) "I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each TR NO_X Annual unit at the source."

(ii) "I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR NO_X Annual Trading Program on behalf of the owners and operators of the source and of each TR NO_X Annual 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 order issued to me by the Administrator regarding the source or unit."

(iii) "Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a TR NO_X Annual unit, or where a utility or industrial customer purchases power from a TR NO_X Annual unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each TR NO_X Annual unit at the source; and TR NO_X Annual allowances and proceeds of transactions involving TR NO_X Annual allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of TR NO_X Annual allowances by contract, TR NO_X Annual allowances and proceeds of transactions involving TR NO_X Annual allowances will be deemed to be held or distributed in accordance with the contract."

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.417 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under § 97.416 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 97.416 is received by the Administrator.

(b) Except as provided in § 97.415(a) or (b), no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the TR NO_X Annual Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of TR NO_X Annual allowance transfers.

§ 97.418 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.418(d) shall be deemed to be an electronic submission by me."

(ii) "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.418(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.418 is terminated."

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

§ 97.419 [Reserved]

§ 97.420 Establishment of Allowance Management System accounts.

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under § 97.416, the Administrator will establish a compliance account for the TR NO_X Annual source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *General accounts*—(1) *Application for general account.*

(i) Any person may apply to open a general account, for the purpose of holding and transferring TR NO_X Annual allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to TR NO_X Annual allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the TR NO_X Annual allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to TR NO_X Annual allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR NO_X Annual 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 regarding the general account."

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of authorized account representative and alternate authorized account representative.* (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator: (A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to TR NO_X Annual allowances held in the general account in all matters pertaining to the TR NO_X Annual Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to TR NO_X Annual allowances held in the general account shall be bound by any order or decision issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (b)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to TR NO_X Annual allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the TR NO_X Annual 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."

(iii) Except in this section, whenever the term "authorized account representative" is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) *Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.* (i) The authorized account representative of 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 authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the TR NO_X Annual allowances in the general account.

(ii) The alternate authorized account representative of 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 authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the TR NO_X Annual allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to TR NO_X Annual allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to NO_X Annual allowances in the general account, including the addition of a new person, the authorized account representative or any alternate 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 TR NO_X Annual allowances in the general account to include the change.

(4) *Objections concerning authorized account representative and alternate authorized account representative.* (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)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the TR NO_X Annual Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of TR NO_X Annual allowance transfers.

(5) *Delegation by authorized account representative and alternate authorized account representative.* (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (b)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (b)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.420(b)(5)(iv) shall be deemed to be an electronic submission by me."; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.420(b)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.420(b)(5) is terminated.".

(iv) A notice of delegation submitted under paragraph (b)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (b)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (b)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6)(i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted TR NO_X Annual allowance transfer under § 97.422 for any TR NO_X Annual allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no TR NO_X Annual allowance transfers to or from the account for a 12-month period or longer and does not contain any TR NO_X Annual allowances, the Administrator may notify the authorized account representative for the account that the account will be closed after 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 TR NO_X Annual allowance transfer under § 97.422 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

(d) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of an Allowance Management System account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of TR NO_X Annual allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 97.414(a) and 97.418 or paragraphs (b)(2)(ii) and (b)(5) of this section.

§ 97.421 Recordation of TR NO_X Annual allowance allocations.

(a) By September 1, 2011, the Administrator will record in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated for the TR NO_X Annual units at the source in accordance with §§ 97.411(a) for the control periods in 2012, 2013, and 2014.

(b) By June 1, 2012 and June 1 of each year thereafter, the Administrator will record in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated for the TR NO_X Annual units at the source in accordance with § 97.411(a) for the control period in the third year after the year of the applicable recordation deadline under this paragraph.

(c) By September 1, 2012 and September 1 of each year thereafter, the Administrator will record in each TR NO_X Annual source's compliance account the TR NO_X Annual allowances allocated for the TR NO_X Annual units at the source in accordance with § 97.412 for the control period in the year of the applicable recordation deadline under this paragraph.

(d) When recording the allocation of TR NO_X Annual allowances for a TR NO_X Annual unit in a compliance account, the Administrator will assign each TR NO_X Annual allowance a unique identification number that will include digits identifying the year of the control period for which the TR NO_X Annual allowance is allocated.

§ 97.422 Submission of TR NO_X Annual allowance transfers.

(a) An authorized account representative seeking recordation of a TR NO_X Annual allowance transfer shall submit the transfer to the Administrator.

(b) A TR NO_X Annual allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each TR NO_X Annual allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each TR NO_X Annual allowance identified by serial number in the transfer.

§ 97.423 Recordation of TR NO_X Annual allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a TR NO_X Annual allowance transfer, the Administrator will record a TR NO_X Annual allowance transfer by moving each TR NO_X Annual allowance from the transferor account to the transferee account as specified by the request, provided that the transfer is correctly submitted under § 97.422.

(b)(1) A TR NO_X Annual allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any TR NO_X Annual allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 97.424 for the control period immediately before such allowance transfer deadline.

(2) A TR NO_X Annual allowance transfer that is submitted for recordation after the deadline for holding TR NO_X Annual allowances described in § 97.425(b)(5) and that includes any TR NO_X Annual allowances allocated for a control period before the year of such deadline will not be recorded until after the Administrator completes the deductions under § 97.425 for the control period immediately before the year of such deadline.

(c) Where a TR NO_X Annual allowance transfer is not correctly submitted under § 97.422, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a TR NO_X Annual allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a TR NO_X Annual allowance transfer that is not correctly submitted under § 97.422, the Administrator will notify the 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.

§ 97.424 Compliance with TR NO_X Annual emissions limitation.

(a) *Availability for deduction for compliance.* TR NO_X Annual allowances are available to be deducted for compliance with a source's TR NO_X Annual emissions limitation for a control period in a given year only if the TR NO_X Annual allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in the source's compliance account as of the allowance transfer deadline for such control period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 97.423, of TR NO_X Annual allowance transfers submitted by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account TR NO_X Annual allowances available under paragraph

(a) of this section in order to determine whether the source meets the TR NO_X Annual emissions limitation for such control period, as follows:

(1) Until the amount of TR NO_X Annual allowances deducted equals the number of tons of total NO_X emissions from all TR NO_X Annual units at the source for such control period; or

(2) If there are insufficient TR NO_X Annual allowances to complete the deductions in paragraph (b)(1) of this section, until no more TR NO_X Annual allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of TR NO_X Annual allowances by serial number.* The authorized account representative for a source's compliance account may request that specific TR NO_X Annual allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the TR NO_X Annual source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR NO_X Annual allowances under paragraph (b) or (d) of this section from the source's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR NO_X Annual allowances in such request, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any TR NO_X Annual allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR NO_X Annual allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Deductions for excess emissions.* After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the TR NO_X Annual source has excess emissions, the Administrator will deduct from the source's compliance account an amount of TR NO_X Annual allowances, allocated for the control period in the immediately following year, equal to two times the number of tons of the source's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.425 Compliance with TR NO_X Annual assurance provisions.

(a) *Availability for deduction.* TR NO_X Annual allowances are available to be deducted for compliance with the TR NO_X Annual assurance provisions for a control period in a given year by an owner of one or more TR NO_X Annual units in a State only if the TR NO_X Annual allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in a compliance account, designated by the owner in accordance with paragraph (b)(4)(ii) of this section, of one of the owner's TR NO_X Annual sources in the State as of the deadline established in paragraph (b)(5) of this section.

(b) *Deductions for compliance.* The Administrator will deduct TR NO_X Annual allowances available under paragraph (a) of this section for compliance with the TR NO_X Annual assurance provisions for a State for a control period in a given year in accordance with the following procedures:

(1) By June 1, 2015 and June 1 of each year thereafter, the Administrator will:

(i) Calculate, separately for each State, the total amount of NO_X emissions from all TR NO_X Annual units in the State during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total amount of NO_X emissions exceeds the State assurance level as described in § 97.406(c)(2)(iii); and

(ii) Promulgate a notice of availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the NO_X emissions for each TR NO_X Annual unit and of the amounts described in §§ 97.406(c)(2)(iii)(A) and (B) for each State.

(2) The Administrator will provide an opportunity for submission of objections to the calculations referenced by each notice described in paragraph (b)(1) of this section.

(i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations for each TR NO_X Annual unit and each State for the control period in the year involved are in accordance with § 97.406(c)(2)(iii) and §§ 97.406(b) and 97.430 through 97.435.

(ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By August 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.

(3) For each notice of data availability required in paragraph (b)(2)(ii) of this section and for any State identified in such notice as having TR NO_X Annual sources with total NO_X emissions exceeding the State assurance level for a control period, as described in § 97.406(c)(2)(iii):

(i) By August 15 immediately after the promulgation of such notice, the designated representative of each TR NO_X Annual source in each such State shall submit a statement, in a format prescribed by the Administrator:

(A) Listing all the owners of each TR NO_X Annual unit at the source, explaining how the selection of each owner for inclusion on the list is consistent with the definition of "owner" in § 97.402, and listing, separately for each unit, the percentage of the legal, equitable, leasehold, or contractual reservation or entitlement for each such owner as of midnight of December 31 of the control period in the year involved; and

(B) For each TR NO_X Annual unit at the source that operates during, but is allocated no TR NO_X Annual allowances for, the control period in the year involved, identifying whether the unit is a coal-fired boiler, simple combustion turbine, or combined cycle turbine cycle and providing the unit's allowable NO_X emission rate for such control period.

(ii) By September 15 immediately after the promulgation of such notice, the Administrator will calculate, for each such State and each owner of one or more TR NO_X Annual units in the State and for the control period in the year involved, each owner's share of the total NO_X emissions from all TR NO_X Annual units in the State, each owner's assurance level, and the amount (if any) of TR NO_X Annual allowances that each owner must hold in accordance with the calculation formula in § 97.406(c)(2)(i) and will promulgate a notice of availability of the results of these calculations.

(iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(3)(ii) of this section.

(A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations for each owner for the control period in the year involved are consistent with the NO_X emissions for the relevant TR NO_X Annual units as set forth in the notice required in paragraph (b)(2)(ii) of this section, the definitions of "owner", "owner's assurance level", and "owner's share" in § 97.402, and the calculation formula in § 97.406(c)(2)(i) and shall not raise any issues about any data used in the notice of data availability required in paragraph (b)(2)(ii) of this section.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are consistent with the data and provisions referenced in paragraph (b)(3)(iii)(A) of this section. By November 15 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(3)(iii)(A) of this section.

(4) By December 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section:

(i) Each owner identified, in such notice, as owning one or more TR NO_X Annual units in a State and as being required to hold TR NO_X Annual allowances shall designate the compliance account of one of the sources at which such unit or units are located to hold such required TR NO_X Annual allowances;

(ii) The authorized account representative for the compliance account designated under paragraph (b)(4)(i) of this section shall submit to the Administrator a statement, in a format prescribed by the Administrator, making this designation.

(5)(i) As of midnight of December 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section, each owner described in paragraph (b)(4)(i) of this section shall hold in the compliance account designated by the owner in accordance with paragraph (b)(4)(ii) of this section the total amount of TR NO_X Annual allowances, available for deduction under paragraph (a) of this section, equal to the amount the owner is required to hold as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(5)(i) of this section, if December 15 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(6) After December 15 (or the date described in paragraph (b)(5)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section and after the recordation, in accordance with § 97.423, of TR NO_X Annual allowance transfers submitted by midnight of such date, the Administrator will deduct from each compliance account designated in accordance with paragraph (b)(4)(ii) of this section, TR NO_X Annual allowances available under paragraph (a) of this section, as follows:

(i) Until the amount of TR NO_X Annual allowances deducted equals the amount that the owner designating the compliance account is required to hold as calculated by the Administrator and referenced in the notice required in paragraph (b)(3)(iii)(B) of this section; or

(ii) If there are insufficient TR NO_X Annual allowances to complete the deductions in paragraph (b)(6)(i) of this section, until no more TR NO_X Annual allowances available under paragraph (a) of this section remain in the compliance account.

(7) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notices of data availability required in paragraphs (b)(2)(ii) and (b)(3)(iii)(B) of this section respectively for a control period, of any data used in making the calculations referenced in such notice, the amount of TR NO_X Annual allowances that each owner is required to hold in accordance with § 97.406(c)(2)(i) for the control period in the year involved shall continue to be such amount as calculated by the Administrator and referenced in such notice required in paragraph (b)(3)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of TR NO_X Annual allowances that owners are required to hold in accordance with the calculation formula in § 97.406(c)(2)(i) for the control period in the year involved with regard to the State involved, provided that—

(A) With regard to such litigation involving such notice required in paragraph (b)(2)(ii) of this section, such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(ii) of this section; and

(B) With regard to such litigation involving such notice required in paragraph (b)(3)(iii) of this section, such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(3)(iii) of this section.

(ii) If any such data are revised by the owners and operators of a source whose designated representative submitted such data under paragraph (b)(3)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of TR NO_X Annual allowances that owners are required to hold in accordance with the calculation formula in § 97.406(c)(2)(i) for the control period in the year involved with regard to the State involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(3)(iii)(B) of this section.

(iii) If the revised data are used to recalculate, in accordance with paragraphs (b)(7)(i) and (b)(7)(ii) of this section, the amount of TR NO_X Annual allowances that an owner is required to hold for the control period in the year involved with regard to the State involved-

(A) Where the amount of TR NO_X Annual allowances that an owner is required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owner shall hold the additional amount of TR NO_X Annual allowances in the compliance account designated by the owner in accordance with paragraph (b)(4)(ii) of this section. The owner's failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owner's failure to hold such additional amount, as required, as of the new deadline shall be a violation of the Clean Air Act. Each TR NO_X Annual allowance that the owner fails to hold as required as of the new deadline, and each day in the control period in the year involved, shall be a separate violation of the Clean Air Act. After such deadline, the Administrator will make the appropriate deductions from the compliance account.

(B) For an owner for which the amount of TR NO_X Annual allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in the compliance account that the owner designated in accordance with paragraph (b)(4)(ii) of this section, an amount of TR NO_X Annual allowances equal to the amount of the decrease to the extent such amount was previously deducted from the compliance account under paragraph (b)(6) of this section (and has not already been restored to the compliance account) for the control period in the year involved.

(C) Each TR NO_X Annual allowance held and deducted under paragraph (b)(7)(iii)(A) of this section, or recorded under paragraph (b)(7)(iii)(B) of this section, as a result of recalculation of requirements under the TR NO_X Annual assurance provisions for a control period in a given year must be a TR NO_X Annual allowance allocated for a control period in the same or a prior year.

(c)(1) *Identification of TR NO_X Annual allowances by serial number.* The authorized account representative for each source's compliance account designated in accordance with paragraph (b)(4)(ii) of this section may request that specific TR NO_X Annual allowances, identified by serial number, in the compliance account be deducted in accordance with paragraph (b)(6) or (7) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance-holding deadline described in paragraph (b)(5) of this section and include, in a format prescribed by the Administrator, the identification of the compliance account and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR NO_X Annual allowances under paragraphs (b)(6) and (7) of this section from each source's compliance account designated under paragraph (b)(4)(ii) of this section in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR NO_X Annual allowances in such request, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any TR NO_X Annual allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR NO_X Annual allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraph (b) of this section.

§ 97.426 Banking.

(a) A TR NO_X Annual allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any TR NO_X Annual allowance that is held in a compliance account or a general account will remain in such account unless and until the TR NO_X Annual allowance is deducted or transferred under § 97.411(c), § 97.423, § 97.424, § 97.425, 97.427, 97.428, 97.442, or 97.443.

§ 97.427 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.428 Administrator's action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the TR NO_X Annual Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct TR NO_X Annual allowances from or transfer TR NO_X Annual allowances to a source's compliance account based on the information in a submission, as adjusted under paragraph (a)(1) of this section, and record such deductions and transfers.

§ 97.429 [Reserved]

§ 97.430 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a TR NO_X Annual unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subpart H of part 75 of this chapter. For purposes of applying such requirements, the definitions in § 97.402 and in § 72.2 of this chapter shall apply, the terms "affected unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") in part 75 of this chapter shall be deemed to refer to the terms "TR NO_X Annual unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") respectively as defined in § 97.402, and the term "newly affected unit" shall be deemed to mean "newly affected TR NO_X Annual unit". The owner or operator of a unit that is not a TR NO_X Annual unit but that is monitored under § 75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a TR NO_X Annual unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each TR NO_X Annual unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO_X mass emissions and individual unit heat input (including all systems required to monitor NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under § 97.431 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a TR NO_X Annual unit that commences commercial operation before July 1, 2011, January 1, 2012;

(2) For the owner or operator of a TR NO_X Annual unit that commences commercial operation on or after July 1, 2011, the later of the following:

(i) January 1, 2012; or

(ii) 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation;

(3) For the owner or operator of a TR NO_X Annual unit for which construction of a new stack or flue or installation of add-on NO_X emission

controls is completed after the applicable deadline under paragraph (b)(1) or (2) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO_X emissions controls;

(4) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved, by the date specified in § 97.441(c); and

(5) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a TR NO_X Annual opt-in unit, by the date on which the TR NO_X Annual opt-in unit enters the TR NO_X Annual Trading Program as provided in § 97.441(h).

(c) *Reporting data.* The owner or operator of a TR NO_X Annual unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NO_X concentration, NO_X emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NO_X mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(d) *Prohibitions.* (1) No owner or operator of a TR NO_X Annual unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 97.435.

(2) No owner or operator of a TR NO_X Annual unit 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.

(3) No owner or operator of a TR NO_X Annual unit 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 or heat input, 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.

(4) No owner or operator of a TR NO_X Annual unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 97.405 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 Administrator 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 designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 97.431(d)(3)(i).

(e) *Long-term cold storage.* The owner or operator of a TR NO_X Annual unit is subject to the applicable provisions of § 75.4(d) of this chapter concerning units in long-term cold storage.

§ 97.431 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a TR NO_X Annual unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 97.430(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendices B, D, and E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 97.430(a)(1) that is exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously 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 § 75.12 or § 75.17 of this chapter, the designated representative shall resubmit the petition to the Administrator under § 97.435 to determine whether the approval applies under the TR NO_X Annual Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a TR NO_X Annual unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (*i.e.,* a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under § 97.430(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under § 97.430(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 97.430(b).

In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 97.430(a)(1) that may significantly affect the ability of the system to accurately measure or record NO_X mass emissions or heat input rate or to meet the quality-assurance and quality-control 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 in accordance with § 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 may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include replacement of the analyzer, complete

replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system, and any excepted NO_X monitoring system under appendix E to part 75 of this chapter, under § 97.430(a)(1) are subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* For initial certification of a continuous monitoring system under § 97.430(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words "certification" and "initial certification" are replaced by the word "recertification" and the word "certified" is replaced by with the word "recertified".

(i) *Notification of certification.* The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with § 97.433.

(ii) *Certification application.* The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the TR NO_X Annual Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, 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 Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) *Certification application approval process.* The Administrator 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 (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that 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 TR NO_X Annual 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 Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period specified in paragraph (d)(3) of this section shall not begin before receipt of a complete certification application.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator 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 Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter).

(D) *Audit decertification.* The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 97.432(b).

(v) *Procedures for loss of certification.* If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(*1*) For a disapproved NO_X emission rate (*i.e.,* NO_X-diluent) system, the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(*2*) For a disapproved NO_X pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NO_X and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(*3*) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(*4*) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(*5*) For a disapproved excepted NO_X monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 97.432 Monitoring system out-of-control periods.

(a) *General provisions.* Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, 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 monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 97.431 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 Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system 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 for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 97.431 for each disapproved monitoring system.

§ 97.433 Notifications concerning monitoring.

The designated representative of a TR NO_X Annual unit shall submit written notice to the Administrator in accordance with § 75.61 of this chapter.

§ 97.434 Recordkeeping and reporting.

(a) *General provisions.* The designated representative shall comply with all recordkeeping and reporting requirements in paragraphs (b) through (e) of this section, the applicable recordkeeping and reporting requirements under § 75.73 of this chapter, and the requirements of § 97.414(a).

(b) *Monitoring plans.* The owner or operator of a TR NO_X Annual unit shall comply with requirements of § 75.73(c) and (e) of this chapter.

(c) *Certification applications.* The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under § 97.431, including the information required under § 75.63 of this chapter.

(d) *Quarterly reports.* The designated representative shall submit quarterly reports, as follows:

(1) The designated representative shall report the NO_X mass emissions data and heat input data for the TR NO_X Annual unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering January 1, 2012 through March 31, 2012;

(ii) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.430(b), unless that quarter is the third or fourth quarter of 2011, in which case reporting shall commence in the quarter covering January 1, 2012 through March 31, 2012;

(iii) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved, the calendar quarter corresponding to the date specified in § 97.441(c); and

(iv) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a TR NO_X Annual opt-in unit, the calendar quarter corresponding to the date on which the TR NO_X Annual opt-in unit enters the TR NO_X Annual Trading Program as provided in § 97.441(h).

(2) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.73(f) of this chapter.

(3) For TR NO_X Annual units that are also subject to the Acid Rain Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the NO_X mass emission data, heat input data, and other information required by this subpart.

(4) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(ii) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(2) of this section.

(e) *Compliance certification.* The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) 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:

(1) 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

(2) For a unit with add-on NO_X emission controls and for all hours where NO_X 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 quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NO_X emissions.

§ 97.435 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a TR NO_X Annual unit may submit a petition under § 75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§ 97.430 through 97.434 or paragraph (5)(i) or (ii) of the definition of "owner's share" in § 97.402.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(i) Identification of each unit and source covered by the petition;

(ii) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(iii) A description and diagram of any equipment and procedures used in the proposed alternative;

(iv) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be *de minimis;* and

(v) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

§ 97.440 General requirements for TR NO_X Annual opt-in units.

(a) A TR NO_X Annual opt-in unit must be a unit that:

(1) Is located in a State;

(2) Is not a TR NO_X Annual unit under § 97.404;

(3) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect; and

(4) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of this subpart.

(b) A TR NO_X Annual opt-in unit shall be deemed to be a TR NO_X Annual unit for purposes of applying this subpart, except for §§ 97.405, 97.411, and 97.412.

(c) Solely for purposes of applying the requirements of §§ 97.413 through 97.418 and §§ 97.430 through 97.435, a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved under § 97.442 shall be deemed to be a TR NO_X Annual unit.

(d) Any TR NO_X Annual opt-in unit, and any unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved under § 97.442, located at the same source as one or more TR NO_X Annual units shall have the same designated representative and alternate designated representative as such TR NO_X Annual units.

§ 97.441 Opt-In process.

A unit meeting the requirements for a TR NO_X Annual opt-in unit in § 97.440(a) may become a TR NO_X Annual opt-in unit only if, in accordance with this section, the designated representative of the unit submits a complete TR opt-in application for the unit and the Administrator approves the application.

(a) *Applying to opt in.* The designated representative of the unit may submit a complete TR opt-in application for the unit at any time, except as provided under § 97.442(e). A complete TR opt-in application shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the unit and the source where the unit is located, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, and unit identification number and type;

(2) A certification that the unit:

(i) Is not a TR NO_X Annual unit under § 97.404;

(ii) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(iii) Vents all of its emissions to a stack; and

(iv) Has documented heat input (greater than 0 mmBtu) for more than 876 hours during the 6 months immediately preceding submission of the TR opt-in application;

(3) A monitoring plan in accordance with §§ 97.430 through 97.435;

(4) A statement that the unit, if approved to become a TR NO_X Annual unit under paragraph (g) of this section, may withdraw from the TR NO_X Annual Trading Program only in accordance with § 97.442;

(5) A statement that the unit, if approved to become a TR NO_X Annual unit under paragraph (g) of this section, is subject to, and the owners and operators of the unit must comply with, the requirements of § 97.443;

(6) A complete certificate of representation under § 97.416 consistent with § 97.440, if no designated representative has been previously designated for the source that includes the unit; and

(7) The signature of the designated representative and the date signed.

(b) Interim review of monitoring plan. The Administrator will determine, on an interim basis, the sufficiency of the monitoring plan submitted under paragraph (a)(3) of this section. The monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the NO_X emission rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with §§ 97.430 through 97.435. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(c) Monitoring and reporting. (1)(i) If the Administrator determines that the monitoring plan is sufficient under paragraph (b) of this section, the owner or operator of the unit shall monitor and report the NO_X emission rate and the heat input of the unit and all other applicable parameters, in accordance with §§ 97.430 through 97.435, starting on the date of certification of the necessary monitoring systems under §§ 97.430 through 97.435 and continuing until the TR opt-in application submitted under paragraph (a) of this section is disapproved under this section or, if such TR opt-in application is approved, the date and time when the unit is withdrawn from the TR NO_X Annual Trading Program in accordance with § 97.442.

(ii) The monitoring and reporting under paragraph (c)(1)(i) of this section shall cover the entire control period immediately before the date on which the unit enters the TR NO_X Annual Trading Program under paragraph (h) of this section, during which period monitoring system availability must not be less than 98 percent under §§ 97.430 through 97.435 and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the NO_X emission rate and the heat input of the unit are monitored and reported in accordance with §§ 97.430 through 97.435 for one or more entire control periods, in addition to the control period under paragraph (c)(1)(ii) of this section, during which control periods monitoring system availability is not less than 98 percent under §§ 97.430 through 97.435 and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the TR NO_X Annual Trading Program under paragraph (h) of this section, such information shall be used as provided in paragraphs (e) and (f) of this section.

(d) *Statement on compliance.* After submitting to the Administrator all quarterly reports required for the unit under paragraph (c) of this section, the designated representative shall submit, in a format prescribed by the Administrator, to the Administrator a statement that, for the years covered by such quarterly reports, the unit was in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(e) *Baseline heat input.* The unit's baseline heat input shall equal:

(1) If the unit's NO_X emission rate and heat input are monitored and reported for only one entire control period, in accordance with paragraph (c) of this section, the unit's total heat input (in mmBtu) for such control period; or

(2) If the unit's NO_X emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, the average of the amounts of the unit's total heat input (in mmBtu) for such control periods.

(f) *Baseline NO_X emission rate.* The unit's baseline NO_X emission rate shall equal:

(1) If the unit's NO_X emission rate and heat input are monitored and reported for only one entire control period, in accordance with paragraph (c) of this section, the unit's NO_X emission rate (in lb/mmBtu) for such control period;

(2) If the unit's NO_X emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, and the unit does not have add-on NO_X emission controls during any such control periods, the average of the amounts of the unit's NO_X emission rate (in lb/mmBtu) for such control periods; or

(3) If the unit's NO_X emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, and the unit has add-on NO_X emission controls during any such control periods, the average of the amounts of the unit's NO_X emission rate (in lb/mmBtu) for such control periods during which the unit has add-on NO_X emission controls.

(g) *Review of TR opt-in application.* (1) After the designated representative submits the complete TR opt-in application, quarterly reports, and statement required in paragraphs (a), (c), and (d) of this section and if the Administrator determines that the designated representative shows that the unit meets the requirements for a TR NO_X Annual opt-in unit in § 97.440, the element certified in paragraph (a)(2)(iv) of this section, and the monitoring and reporting requirements of paragraph (c) of this section, the Administrator will issue a written approval of the TR opt-in application for the unit. The written approval will state the unit's baseline heat input and baseline NO_X emission rate. The Administrator will thereafter establish a compliance account for the source that includes the unit unless the source already has a compliance account.

(2) Notwithstanding paragraphs (a) through (f) of this section, if, at any time before the TR opt-in application is approved under paragraph (g)(1) of this section, the Administrator determines that the unit cannot meet the requirements for a TR NO_X Annual opt-in unit in § 97.440, the element certified in paragraph (a)(2)(iv) of this section, or the monitoring and reporting requirements in paragraph (c) of this section, the Administrator will issue a written disapproval of the TR opt-in application for the unit.

(h) *Date of entry into TR NO_X Annual Trading Program.* A unit for which a TR opt-in application is approved under paragraph (g)(1) of this section shall become a TR NO_X Annual opt-in unit, and a TR NO_X Annual unit, effective as of the later of January 1, 2012 or January 1 of the first control period during which such approval is issued.

§ 97.442 Withdrawal of TR NO_X Annual opt-in unit from TR NO_X Annual Trading Program.

A TR NO_X Annual opt-in unit may withdraw from the TR NO_X Annual Trading Program only if, in accordance with this section, the designated representative of the unit submits a request to withdraw the unit and the Administrator issues a written approval of the request.

(a) *Requesting withdrawal.* In order to withdraw the TR NO_X Annual opt-in unit from the TR NO_X Annual Trading Program, the designated representative of the unit shall submit to the Administrator a request to withdraw the unit effective as of midnight of December 31 of a specified calendar year, which date must be at least 4 years after December 31 of the year of the unit's entry into the TR NO_X Annual Trading Program under § 97.441(h). The request shall be in a format prescribed by the Administrator and shall be submitted no later than 90 days before the requested effective date of withdrawal.

(b) *Conditions for withdrawal.* Before a TR NO_X Annual opt-in unit covered by the request to withdraw may withdraw from the TR NO_X Annual Trading Program, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the TR NO_X Annual opt-in unit must meet the requirement to hold TR NO_X Annual allowances under §§ 97.424 and 97.425 and cannot have any excess emissions.

(2) After the requirement under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the TR NO_X Annual opt-in unit TR NO_X Annual allowances equal in amount to and allocated for the same or a prior control period as any TR NO_X Annual allowances allocated to the TR NO_X Annual opt-in unit under § 97.444 for any control period after the date on which the withdrawal is to be effective. If there are no other TR NO_X Annual units at the source, the Administrator will close the compliance account, and the owners and operators of the TR NO_X Annual opt-in unit may submit a TR NO_X Annual allowance transfer for any remaining TR NO_X Annual allowances to another Allowance Management System account in accordance with §§ 97.422 and 97.423.

(c) *Approving withdrawal.* (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of TR NO_X Annual allowances required), the Administrator will issue a written approval of the request to withdraw, which will become effective as of midnight on December 31 of the calendar year for which the withdrawal was requested. The unit covered by the request shall continue to be a TR NO_X Annual opt-in unit until the effective date of the withdrawal and shall comply with all requirements under the TR NO_X

Annual Trading Program concerning any control periods for which the unit is a TR NO_X Annual opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the Administrator will issue a written disapproval of the request to withdraw. The unit covered by the request shall continue to be a TR NO_X Annual opt-in unit.

(d) *Reapplication upon failure to meet conditions of withdrawal.* If the Administrator disapproves the request to withdraw, the designated representative of the unit may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(e) *Ability to reapply to the TR NO_X Annual Trading Program.* Once a TR NO_X Annual opt-in unit withdraws from the TR NO_X Annual Trading Program, the designated representative may not submit another opt-in application under § 97.441 for such unit before the date that is 4 years after the date on which the withdrawal became effective.

§ 97.443 Change in regulatory status.

(a) *Notification.* If a TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404, then the designated representative of the unit shall notify the Administrator in writing of such change in the TR NO_X Annual opt-in unit's regulatory status, within 30 days of such change.

(b) *Administrator's actions.* (1) If a TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404, the Administrator will deduct, from the compliance account of the source that includes the TR NO_X Annual opt-in unit that becomes a TR NO_X Annual unit under § 97.404, TR NO_X Annual allowances equal in amount to and allocated for the same or a prior control period as:

(i) Any TR NO_X Annual allowances allocated to the TR NO_X Annual opt-in unit under § 97.444 for any control period starting after the date on which the TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404; and

(ii) If the date on which the TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404 is not December 31, the TR NO_X Annual allowances allocated to the TR NO_X Annual opt-in unit under § 97.444 for the control period that includes the date on which the TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404—

(A) Multiplied by the ratio of the number of days, in the control period, starting with the date on which the TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404, divided by the total number of days in the control period, and

(B) Rounded to the nearest allowance.

(2) The designated representative shall ensure that the compliance account of the source that includes the TR NO_X Annual opt-in unit that becomes a TR NO_X Annual unit under § 97.404 contains the TR NO_X Annual allowances necessary for completion of the deduction under paragraph (b)(1) of this section.

(3)(i) For control periods starting after the date on which the TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404, the TR NO_X Annual opt-in unit will be allocated TR NO_X Annual allowances in accordance with § 97.412.

(ii) If the date on which the TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404 is not December 31, the following amount of TR NO_X Annual allowances will be allocated to the TR NO_X Annual opt-in unit (as a TR NO_X Annual unit) in accordance with § 97.412 for the control period that includes the date on which the TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404:

(A) The amount of TR NO_X Annual allowances otherwise allocated to the TR NO_X Annual opt-in unit (as a TR NO_X Annual unit) in accordance with § 97.412 for the control period;

(B) Multiplied by the ratio of the number of days, in the control period, starting with the date on which the TR NO_X Annual opt-in unit becomes a TR NO_X Annual unit under § 97.404, divided by the total number of days in the control period; and (C) Rounded to the nearest allowance.

§ 97.444 TR NO_X Annual allowance allocations to TR NO_X Annual opt-in units.

(a) *Timing requirements.* (1) When the TR opt-in application is approved for a unit under § 97.441(g), the Administrator will issue TR NO_X Annual allowances and allocate them to the unit for the control period in which the unit enters the TR NO_X Annual Trading Program under § 97.441(h), in accordance with paragraph (b) of this section.

(2) By no later than October 31 of the control period after the control period in which a TR NO_X Annual opt-in unit enters the TR NO_X Annual Trading Program under § 97.441(h) and October 31 of each year thereafter, the Administrator will issue TR NO_X Annual allowances and allocate them to the TR NO_X Annual opt-in unit for the control period that includes such allocation deadline and in which the unit is a TR NO_X Annual opt-in unit, in accordance with paragraph (b) of this section.

(b) *Calculation of allocation.* For each control period for which a TR NO_X Annual opt-in unit is to be allocated TR NO_X Annual allowances, the Administrator will issue and allocate TR NO_X Annual allowances in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the TR NO_X Annual allowance allocation will be the lesser of:

(i) The TR NO_X Annual opt-in unit's baseline heat input determined under § 97.441(g); or

(ii) The TR NO_X Annual opt-in unit's heat input, as determined in accordance with §§ 97.430 through 97.435, for the immediately prior control period, except when the allocation is being calculated for the control period in which the TR NO_X Annual opt-in unit enters the TR NO_X Annual Trading Program under § 97.441(h).

(2) The NO_X emission rate (in lb/mmBtu) used for calculating TR NO_X Annual allowance allocations will be the lesser of:

(i) The TR NO_X Annual opt-in unit's baseline NO_X emission rate (in lb/mmBtu) determined under § 97.441(g) and multiplied by 70 percent; or

(ii) The most stringent State or Federal NO_X emissions limitation applicable to the TR NO_X Annual opt-in unit at any time during the control period for which TR NO_X Annual allowances are to be allocated.

(3) The Administrator will issue TR NO_X Annual allowances and allocate them to the TR NO_X Annual opt-in unit in an amount equaling the heat input under paragraph (b)(1) of this section, multiplied by the NO_X emission rate under paragraph (b)(2) of this section, divided by 2,000 lb/ton, and rounded to the nearest allowance.

(c) *Recordation.* (1) The Administrator will record, in the compliance account of the source that includes the TR NO_X Annual opt-in unit, the TR NO_X Annual allowances allocated to the TR NO_X Annual opt-in unit under paragraph (a)(1) of this section.

(2) By December 1 of the control period after the control period in which a TR NO_X Annual opt-in unit enters the TR NO_X Annual Trading Program under § 97.441(h) and December 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the TR NO_X Annual opt-in unit, the TR NO_X Annual allowances allocated to the TR NO_X

Annual opt-in unit under paragraph (a)(2) of this section.

36. Part 97 is amended by adding subpart BBBBB to read as follows:

Subpart BBBBB—TR NO_X Ozone Season Trading Program

Subpart BBBBB—TR NO_X Ozone Season Trading Program

§ 97.501 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Transport Rule (TR) NO_X Ozone Season Trading Program, under section 110 of the Clean Air Act and § 52.37(b) of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

§ 97.502 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor) of the United States Environmental Protection Agency, the Administrator's duly authorized representative under this subpart.

Allocate or allocation means, with regard to TR NO_X Ozone Season allowances, the determination by the Administrator of the amount of such TR NO_X Ozone Season allowances to be initially credited to a TR NO_X Ozone Season source or a new unit set-aside.

Allowable NO_X emission rate means, with regard to a unit, the NO_X emission rate limit that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, deductions, and transfers of TR NO_X Ozone Season allowances under the TR NO_X Ozone Season Trading Program. Such allowances are allocated, held, deducted, or transferred only as whole allowances. The Allowance Management System is a component of the CAMD Business System, which is the system used by the Administrator to handle TR NO_X Ozone Season allowances and data related to NO_X emissions.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, holding, transfer, or deduction of TR NO_X Ozone Season allowances.

Allowance transfer deadline means, for a control period, midnight of December 1 (if it is a business day), or midnight of the first business day thereafter (if December 1 is not a business day), immediately after such control period and is the deadline by which a TR NO_X Ozone Season allowance transfer must be submitted for recordation in a TR NO_X Ozone Season source's compliance account in order to be available for use in complying with the source's TR NO_X Ozone Season emissions limitation for such control period in accordance with § 97.524.

Alternate designated representative means, for a TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the TR NO_X Ozone Season Trading Program. If the TR NO_X Ozone Season source is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative as defined in § 72.2 of this chapter, § 97.402, § 97.602, or § 97.702 respectively.

Authorized account representative means, with regard to a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of TR NO_X Ozone Season allowances held in the general account and, with regard to a TR NO_X Ozone Season source's compliance account, the designated representative of the source.

Automated data acquisition and handling system or DAHS means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, 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 this subpart.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

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.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president or the corporation in charge of a principal business function or any other person who performs similar policy or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during 1990 or any year thereafter.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine—

(1) Operating as part of a cogeneration system; and

(2) Producing during the later of 1990 or the 12-month period starting on the date that the unit first produces electricity and during each calendar year after the later of 1990 or the calendar year in which the unit first produces electricity—

(i) For a topping-cycle unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel, except biomass if the unit is a boiler; and

(4) Provided that, if a topping-cycle unit is operated as part of a cogeneration system during a calendar year and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) of this definition, the topping-cycle unit shall be deemed to meet such requirement during that calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, 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; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) 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 § 97.505.

(i) For a unit that is a TR NO_X Ozone Season unit under § 97.504 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a TR NO_X Ozone Season unit under § 97.504 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 97.505, for a unit that is not a TR NO_X Ozone Season unit under § 97.504 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in introductory text of paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a TR NO_X Ozone Season unit under § 97.504.

(i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Commence operation means, with regard to a unit:

(1) To have begun any mechanical, chemical, or electronic process, including start-up of the unit's combustion chamber.

(2) For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source)

after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(3) For a unit that is replaced by a unit at the same source after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the replaced unit's date of commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a TR NO_X Ozone Season source under this subpart, in which any TR NO_X Ozone Season allowance allocations for the TR NO_X Ozone Season units at the source are recorded and in which are held any TR NO_X Ozone Season allowances available for use for a control period in complying with the source's TR NO_X Ozone Season emissions limitation in accordance with § 97.524 and the TR NO_X Ozone Season assurance provisions in accordance with § 97.525.

Continuous emission monitoring system or CEMS means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of NO_X emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 or CO_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§ 97.530 through 97.535. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A NO_X concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X emissions, in parts per million (ppm);

(3) A NO_X emission rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X concentration, in parts per million (ppm), diluent gas concentration, in percent CO_2 or O_2, and NO_X emission rate, in pounds per million British thermal units (lb/mmBtu);

(4) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(5) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(6) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period starting May 1 of a calendar year, except as provided in § 97.506(c)(3), and ending on September 30 of the same year, inclusive.

Designated representative means, for a TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the TR NO_X Ozone Season Trading Program. If the TR NO_X Ozone Season source is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in § 72.2 of this chapter, § 97.402, § 97.602, or § 97.702 respectively.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart.

Excess emissions means any ton of NO_X emitted from the TR NO_X Ozone Season units at a TR NO_X Ozone Season source during a control period that exceeds the TR NO_X Ozone Season emissions limitation for the source.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying §§ 97.504(b)(2)(i)(B), 97.504(b)(2)(ii)(B), and 97.504(b)(2)(iii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 1990 or any calendar year thereafter.

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a unit for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

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 generated by 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 no less 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 maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

Newly affected TR NO_X Ozone Season unit means a unit that was not a TR NO_X Ozone Season unit when it began operating but that thereafter becomes a TR NO_X Ozone Season unit.

Operate or operation means, with regard to a unit, to combust fuel.

Operator means any person who operates, controls, or supervises a TR NO_X Ozone Season unit or a TR NO_X Ozone Season source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means, with regard to a TR NO_X Ozone Season source or a TR NO_X Ozone Season unit at a source respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a TR NO_X Ozone Season unit at the source or the TR NO_X Ozone Season unit;

(2) Any holder of a leasehold interest in a TR NO_X Ozone Season unit at the source or the TR NO_X Ozone Season unit, provided that, 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) on the revenues or income from such TR NO_X Ozone Season unit;

(3) Any purchaser of power from a TR NO_X Ozone Season unit at the source or the TR NO_X Ozone Season unit under a life-of-the-unit, firm power contractual arrangement;

(4) Provided that, for purposes of applying the TR NO_X Ozone Season assurance provisions in §§ 97.506(c)(2) and 97.525, if one or more owners (as defined in paragraphs (1) through (3) of this definition) of one or more TR NO_X Ozone Season units in a State are wholly owned by another, common owner, all such owners shall be treated collectively as a single owner in the State.

Owner's assurance level means:

(1) With regard to a State and control period for which the State assurance level is exceeded as described in § 97.506(c)(2)(iii)(A) and not as described in § 97.506(c)(2)(iii)(B), the owner's share of the State NO_X Ozone Season trading budget with the one-year variability limit for the State for such control period; or

(2) With regard to a State and control period for which the State assurance level is exceeded as described in § 97.506(c)(2)(iii)(B), the owner's share of the State NO_X Ozone Season trading budget with the three-year variability limit for the State for such control period.

Owner's share means:

(1) With regard to a total amount of NO_X emissions from all TR NO_X Ozone Season units in a State during a control period, the total tonnage of NO_X emissions during such control period from all of the owner's TR NO_X Ozone Season units in the State;

(2) With regard to a State NO_X Ozone Season trading budget with a one-year variability limit for a control period, the amount (rounded to the nearest allowance) equal to the total amount of TR NO_X Ozone Season allowances allocated for such control period to all of the owner's TR NO_X Ozone Season units in the State, multiplied by the sum of the State NO_X Ozone Season trading budget under § 97.510(a) and the State's one-year variability limit under § 97.510(b) and divided by such State NO_X Ozone Season trading budget;

(3) With regard to a State NO_X Ozone Season trading budget with a three-year variability limit for a control period, the amount (rounded to the nearest allowance) equal to the total amount of TR NO_X Ozone Season allowances allocated for such control period to all of the owner's TR NO_X Ozone Season units in the State, multiplied by the sum of the State NO_X Ozone Season trading budget under § 97.510(a) and the State's three-year variability limit under § 97.510(b) and divided by such State NO_X Ozone Season trading budget;

(4) Provided that, in the case of a unit with more than one owner, the amount of tonnage of NO_X emissions and of TR NO_X Ozone Season allowances allocated for a control period, with regard to such unit, used in determining each owner's share shall be the amount (rounded to the nearest ton and the nearest allowance) equal to the unit's NO_X emissions and allocation of such allowances, respectively, for such control period multiplied by the percentage of ownership in the unit that the owner's legal, equitable, leasehold, or contractual reservation or entitlement in the unit comprises as of September 30 of such control period;

(5) Provided that, where two or more units emit through a common stack that is the monitoring location from which NO_X mass emissions are reported for a control period for a year, the amount of tonnage of each unit's NO_X emissions used in determining each owner's share for such control period shall be:

(i) The amount (rounded to the nearest ton) of NO_X emissions reported at the common stack multiplied by the quotient of such unit's heat input for such control period divided by the total heat input reported from the common stack for such control period;

(ii) An amount determined in accordance with a methodology that the Administrator determines is consistent with the purposes of this definition and whose adverse effect (if any) the Administrator determines will be de minimis; or

(iii) An amount approved by the Administrator in response to a petition for an alternative requirement submitted in accordance with § 97.535; and

(6) Provided that, in the case of a unit that operates during, but is allocated no TR NO_X Ozone Season allowances for, a control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of TR NO_X Ozone Season allowances for such control period equal to the lesser of—

(i) The unit's allowable NO_X emission rate (in lb per MWe) applicable to such control period, multiplied by a capacity factor of 0.89 (if the unit is a coal-fired boiler), 0.22 (if the unit is a simple combustion turbine), or 0.72 (if the unit is a combined cycle turbine), multiplied by the unit's maximum hourly load as reported in accordance with this subpart and by 3,672 hours/control period, and divided by 2,000 lb/ton; or

(ii) For a unit listed in appendix A to this subpart, the sum of the unit's NO_X emissions in the control period in the last three years during which the unit operated during the control period, divided by three.

Permanently retired means, with regard to a unit, a unit that is unavailable for service and that the unit's owners and operators do not expect to return to service in the future.

Permitting authority means "permitting authority" as defined in §§ 70.2 and 71.2 of this chapter.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to TR NO_X Ozone Season allowances, the moving of TR NO_X Ozone Season allowances by the Administrator into, out of, or between Allowance Management System accounts, 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 § 75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

(1) For a topping-cycle unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle unit, the use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a TR NO_X Ozone Season allowance, the unique identification number assigned to each TR NO_X Ozone Season allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a "solid waste incineration unit" as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of "major source", "stationary source", or "source" as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States or the District of Columbia that is subject to the TR NO_X Ozone Season Trading Program pursuant to § 52.37(b) of this chapter.

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;

(4) Provided that compliance with any "submission" or "service" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Topping-cycle unit means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means total energy of all forms supplied to a unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

$$LHV = HHV - 10.55 (W + 9H)$$

Where:

LHV = lower heating value of the form of energy in Btu/lb,
HHV = higher heating value of the form of energy in Btu/lb,
W = weight % of moisture in the form of energy, and
H = weight % of hydrogen in the form of energy.

Total energy output means the sum of useful power and useful thermal energy produced by the unit.

TR NO_X Annual Trading Program means a multi-state NO_X air pollution control and emission reduction program established by the Administrator in accordance with subpart AAAAA of this part and 52.37(a) of this chapter, as a means of mitigating interstate transport of fine particulates and NO_X.

TR NO_X Ozone Season allowance means a limited authorization issued and allocated by the Administrator under this subpart to emit one ton of NO_X during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the TR NO_X Ozone Season Program.

TR NO_X Ozone Season allowance deduction or deduct TR NO_X Ozone Season allowances means the permanent withdrawal of TR NO_X Ozone Season allowances by the Administrator from a compliance account, e.g., in order to account for compliance with the TR NO_X Ozone Season emissions limitation or assurance provisions.

TR NO_X Ozone Season allowances held or hold TR NO_X Ozone Season allowances means the TR NO_X Ozone Season allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, TR NO_X Ozone Season allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, TR NO_X Ozone Season allowance transfer in accordance with this subpart.

TR NO_X Ozone Season emissions limitation means, for a TR NO_X Ozone Season source, the tonnage of NO_X emissions authorized in a control period by the TR NO_X Ozone Season allowances available for deduction for the source under § 97.524(a) for such control period.

TR NO_X Ozone Season Trading Program means a multi-state NO_X air pollution control and emission reduction program established by the Administrator in accordance with this subpart and 52.37(b) of this chapter, as a means of mitigating interstate transport of ozone and NO_X.

TR NO_X Ozone Season source means a source that includes one or more TR NO_X Ozone Season units.

TR NO_X Ozone Season unit means a unit that is subject to the TR NO_X Ozone Season Trading Program under § 97.504.

TR SO_2 Group 1 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established by the Administrator in accordance with subpart CCCCC of this part and 52.38(b) of this chapter, as a means of mitigating interstate transport of fine particulates and SO_2.

TR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established by the Administrator in accordance with subpart DDDDD of this part and 52.38(c) of this chapter, as a means of mitigating interstate transport of fine particulates and SO_2.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or hour of unit operation means an hour in which a unit combusts any fuel.

Useful power means electricity or mechanical energy that a unit makes available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (e.g., space heating or domestic hot water heating); or

(3) Used in a space cooling application (i.e., in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 97.503 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit
CO_2—carbon dioxide
H_2O—water
hr—hour
kW—kilowatt electrical
kWh—kilowatt hour
lb—pound
mmBtu—million Btu
MWe—megawatt electrical
MWh—megawatt hour
NO_X—nitrogen oxides
O_2—oxygen
ppm—parts per million
scfh—standard cubic feet per hour
SO_2—sulfur dioxide
yr—year

§ 97.504 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State shall be TR NO_X Ozone Season units, and any source that includes one or more such units shall be a TR NO_X Ozone Season source, subject to the requirements of this subpart: Any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a TR NO_X Ozone Season unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a TR NO_X Ozone Season unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State that otherwise is a TR NO_X Ozone Season unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i), (b)(2)(i), or (b)(2)(ii) of this section shall not be a TR NO_X Ozone Season unit:

(1)(i) Any unit:

(A) Qualifying as a cogeneration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If a unit qualifies as a cogeneration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (b)(1)(i) of this section for at least one calendar year, but subsequently no longer meets such qualification and requirements, the unit shall become a TR NO_X Ozone Season unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section.

(2)(i) Any unit commencing operation before January 1, 1985:

(A) Qualifying as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit; and

(B) With an average Ozone Season fuel consumption of fossil fuel for 1985–1987 less than 20 percent (on a Btu basis) and an average Ozone Season fuel consumption of fossil fuel for any 3 consecutive calendar years after 1990 less than 20 percent (on a Btu basis).

(ii) Any unit commencing operation on or after January 1, 1985:

(A) Qualifying as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit; and

(B) With an average Ozone Season fuel consumption of fossil fuel for the first 3 calendar years of operation less than 20 percent (on a Btu basis) and an average Ozone Season fuel consumption of fossil fuel for any 3 consecutive calendar years after 1990 less than 20 percent (on a Btu basis).

(iii) If a unit qualifies as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraph (b)(2)(i) or (ii) of this section for at least 3 consecutive calendar years, but subsequently no longer meets such qualification and requirements, the unit shall become a TR NO_X Ozone Season unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 1990 for which the unit has an average Ozone Season fuel consumption of fossil fuel of 20 percent or more.

(c) A certifying official of an owner or operator of any unit or other equipment may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR NO_X Ozone Season Trading Program to the unit or other equipment.

(1) *Petition content.* The petition shall be in writing and include the identification of the unit or other

equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: "I am authorized to make this submission on behalf of the owners and operators of the unit or other equipment 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) *Response.* The Administrator will issue a written response to the petition and may request supplemental information determined by the Administrator to be relevant to such petition. The Administrator's determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR NO_X Ozone Season Trading Program to the unit or other equipment shall be binding on any permitting authority unless the Administrator determines that the petition or other documents or information provided in connection with the petition contained significant, relevant errors or omissions.

§ 97.505 Retired unit exemption.

(a)(1) Any TR NO_X Ozone Season unit that is permanently retired and is not a TR NO_X Ozone Season opt-in unit shall be exempt from § 97.506(b) and (c)(1), § 97.524, and §§ 97.530 through 97.535.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the TR NO_X Ozone Season unit is permanently retired. Within 30 days of the unit's permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any NO_X, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of 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 before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the TR NO_X Ozone Season 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 exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

§ 97.506 Standard requirements.

(a) *Designated representative requirements.* The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§ 97.513 through 97.518.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.530 through 97.535.

(2) The emissions data determined in accordance with §§ 97.530 through 97.535 shall be used to calculate allocations of TR NO_X Ozone Season allowances under §§ 97.511(a)(2) and (b) and 97.512 and to determine compliance with the TR NO_X Ozone Season emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.530 through 97.535 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) *NO_X emissions requirements*—(1) *TR NO_X Ozone Season emissions limitation.* (i) As of the allowance transfer deadline for a control period, the owners and operators of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, TR NO_X Ozone Season allowances available for deduction for such control period under § 97.524(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Ozone Season units at the source.

(ii) If a TR NO_X Ozone Season source emits NO_X during any control period in excess of the TR NO_X Ozone Season emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall hold the TR NO_X Ozone Season allowances required for deduction under § 97.524(d) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act; and

(B) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) TR NO_X Ozone Season assurance provisions. (i) If the total amount of NO_X emissions from all TR NO_X Ozone Season units in a State during a control period in 2014 or any year thereafter exceeds the State assurance level as described in paragraph (c)(2)(iii) of this section, then each owner whose share of such NO_X emissions during such control period exceeds the owner's assurance level for the State and such control period shall hold, in a compliance account designated by the owner in accordance with § 97.525(b)(4)(ii), TR NO_X Ozone Season allowances available for deduction for such control period under § 97.525(a) in an amount equal to the product, as determined by the Administrator in accordance with § 97.525(b), of multiplying—

(A) The quotient (rounded to the nearest whole number) of the amount by which the owner's share of such NO_X emissions exceeds the owner's assurance level divided by the sum of the amounts, determined for all such owners, by which each owner's share of such NO_X emissions exceeds that owner's assurance level; and

(B) The amount by which total NO_X emissions for all TR NO_X Ozone Season units in the State for such control period exceed the State assurance level as determined in accordance with paragraph (c)(2)(iii) of this section.

(ii) The owner shall hold the TR NO_X Ozone Season allowances required under paragraph (c)(2)(i) of this section, as of midnight of August 1 (if it is a business day), or midnight of the first business day thereafter (if August 1 is not a business day), immediately after such control period.

(iii) The total amount of NO_X emissions from all TR NO_X Ozone Season units in a State during a control period in 2014 or any year thereafter exceeds the State assurance level:

(A) If such total amount of NO_X emissions exceeds the sum, for such control period, of the State NO_X Ozone Season trading budget and the State's one-year variability limit under § 97.510(b); or

(B) If, with regard to a control period in 2016 or any year thereafter, the sum, divided by three, of such total amount of NO_X emissions and the total amounts of NO_X emissions from all TR NO_X Ozone Season units in the State during the control periods in the immediately preceding two years exceeds the sum, for such control period, of the State NO_X Ozone Season trading budget and the State's three-year variability limit under § 97.510(b);

(C) Provided that the amount by which such total amount of NO_X emissions exceeds the State assurance level shall be the greater of the amounts of the exceedance calculated under paragraph (c)(2)(iii)(A) of this section and under paragraph (c)(2)(iii)(B) of this section.

(iv) It shall not be a violation of this subpart or of the Clean Air Act if the total amount of NO_X emissions from all TR NO_X Ozone Season units in a State during a control period exceeds the State assurance level or if an owner's share of total NO_X emissions from the TR NO_X Ozone Season units in a State during a control period exceeds the owner's assurance level.

(v) To the extent an owner fails to hold TR NO_X Ozone Season allowances for a control period in accordance with paragraphs (c)(2)(i) and (ii) of this section,

(A) The owner shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR NO_X Ozone Season allowance that the owner fails to hold for a control period in accordance with paragraphs (c)(2)(i) and (ii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) *Compliance periods.* A TR NO_X Ozone Season unit shall be subject to the requirements:

(i) Under paragraph (c)(1) of this section for the control period starting on the later of September 1, 2012 or the deadline for meeting the unit's monitor certification requirements under § 97.530(b) and for each control period thereafter; and

(ii) Under paragraph (c)(2) of this section for the control period starting on the later of September 1, 2014 or the deadline for meeting the unit's monitor certification requirements under § 97.530(b) and for each control period thereafter.

(4) *Vintage of deducted allowances.* A TR NO_X Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraphs (c)(1) and (2) of this section, for a control period in a calendar year before the year for which the TR NO_X Ozone Season allowance was allocated.

(5) *Allowance Management System requirements.* Each TR NO_X Ozone Season allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) *Limited authorization.* (i) A TR NO_X Ozone Season allowance is a limited authorization to emit one ton of NO_X in accordance with the TR NO_X Ozone Season Trading Program.

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) *Property right.* A TR NO_X Ozone Season allowance does not constitute a property right.

(d) *Title V Permit requirements.* (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_X Ozone Season allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report NO_X emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.530 through 97.535 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) *Additional recordkeeping and reporting requirements.*

(1) Unless otherwise provided, the owners and operators of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 97.516 for the designated representative for the source and each TR NO_X Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; 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 certificate of representation under § 97.516 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NO_X Ozone Season Trading Program, including any monitoring plans and monitoring system certification and recertification applications.

(2) The designated representative of a TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall make all submissions required under the TR NO_X Ozone Season Trading Program, including any submissions required for compliance with the TR NO_X Ozone Season assurance provisions. This requirement does not change, create an exemption from, or or otherwise affect the responsible official submission requirements under a title V operating

permit program in parts 70 and 71 of this chapter.

(f) *Liability.* (1) Any provision of the TR NO_X Ozone Season Trading Program that applies to a TR NO_X Ozone Season source or the designated representative of a TR NO_X Ozone Season source shall also apply to the owners and operators of such source and of the TR NO_X Ozone Season units at the source.

(2) Any provision of the TR NO_X Ozone Season Trading Program that applies to a TR NO_X Ozone Season unit or the designated representative of a TR NO_X Ozone Season unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the TR NO_X Ozone Season Trading Program or exemption under § 97.505 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_X Ozone Season source or TR NO_X Ozone Season unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 97.507 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the TR NO_X Ozone Season 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 TR NO_X Ozone Season 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 TR NO_X Ozone Season Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 97.508 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the TR NO_X Ozone Season Trading Program are set forth in part 78 of this chapter.

§ 97.509 [Reserved]

§ 97.510 State NO_X Ozone Season trading budgets, new-unit set-asides, and variability limits.

(a) The State NO_X Ozone Season trading budgets and new-unit set-asides for allocations of TR NO_X Ozone Season allowances for the control periods in 2012 and thereafter are as follows:

State	NO_X ozone season trading budget (tons)*	New-unit set-aside (tons)
	For 2012 and thereafter	For 2012 and thereafter
Alabama	29,738	892
Arkansas	16,660	500
Connecticut	1,315	39
Delaware	2,450	74
District of Columbia	105	3
Florida	56,939	1,708
Georgia	32,144	964
Illinois	23,570	707
Indiana	49,987	1,500
Kansas	21,433	643
Kentucky	30,908	927
Louisiana	21,220	637
Maryland	7,232	217
Michigan	28,253	848
Mississippi	16,530	496
New Jersey	5,269	158
New York	11,090	333
North Carolina	23,539	706
Ohio	40,661	1,220
Oklahoma	37,087	1,113
Pennsylvania	48,271	1,448
South Carolina	15,222	457
Tennessee	11,575	347
Texas	75,574	2,267
Virginia	12,608	378
West Virginia	22,234	667
Total	641,614	19,249

* Without variability limits.

(b) The States' one-year and three-year variability limits for the State NO_X Ozone Season trading budgets for the control periods in 2014 and thereafter are as follows:

State	One-year variability limits	Three-year variability limits
	2014 and thereafter (tons)	2016 and thereafter (tons)
Alabama	2,974	1,717
Arkansas	2,100	1,212
Connecticut	2,100	1,212
Delaware	2,100	1,212
District of Columbia	2,100	1,212
Florida	5,694	3,287
Georgia	3,214	1,856
Illinois	2,357	1,361
Indiana	4,999	2,886
Kansas	2,143	1,237
Kentucky	3,091	1,784
Louisiana	2,122	1,225
Maryland	2,100	1,212
Michigan	2,825	1,631
Mississippi	2,100	1,212
New Jersey	2,100	1,212
New York	2,100	1,212
North Carolina	2,354	1,359
Ohio	4,066	2,348
Oklahoma	3,709	2,141
Pennsylvania	4,827	2,787
South Carolina	2,100	1,212
Tennessee	2,100	1,212
Texas	7,557	4,363
Virginia	2,100	1,212
West Virginia	2,223	1,284

§ 97.511 Timing requirements for TR NO_X Ozone Season allowance allocations.

(a) *Existing units.* (1) TR NO_X Ozone Season allowances are allocated, for the control periods in 2012 and each year thereafter, as set forth in appendix A to this subpart. Listing a unit in such appendix does not constitute a determination that the unit is a TR NO_X Ozone Season unit, and not listing a unit in such appendix does not constitute a determination that the unit is not a TR NO_X Ozone Season unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit listed in appendix A to this subpart as being allocated TR NO_X Ozone Season allowances does not operate, starting after 2011, during the control period in three consecutive years, such unit will not be allocated the TR NO_X Ozone Season allowances set forth in appendix A to this subpart for the unit for the control periods in the seventh year after the first such year and in each year after that seventh year. All TR NO_X Ozone Season allowances that would otherwise have been allocated to such unit will be allocated to the new unit set-aside for the respective years involved. If such unit resumes operation, the Administrator will allocate TR NO_X Ozone Season allowances to the unit in accordance with paragraph (b) of this section.

(b) *New units.* (1) By April 1, 2012 and April 1 of each year thereafter, the Administrator will calculate the TR NO_X Ozone Season allowance allocation for each TR NO_X Ozone Season unit, in accordance with § 97.512, for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of availability of the results of the calculations.

(2) For each notice of data availability required in paragraph (b)(1) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations are in accordance with § 97.512 and §§ 97.506(b)(2) and 97.530 through 97.535.

(ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By June 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.

(c) *Units that are not TR NO_X Ozone Season units.* For each control period in 2012 and thereafter, if the Administrator determines that TR NO_X Ozone Season allowances were allocated under paragraph (a) of this section for the control period to a recipient that is not actually a TR NO_X Ozone Season unit under § 97.504 as of May 1, 2012 or whose deadline for meeting monitor certification requirements under § 97.530(b)(1) and (2) is after May 1, 2012 or if the Administrator determines that TR NO_X Ozone Season allowances were allocated under paragraph (b) of this section and § 97.512 for the control period to a recipient that is not actually a TR NO_X Ozone Season unit under § 97.504 as of May 1 of the control period, then the Administrator will notify the designated representative and will act in accordance with the following procedures:

(1) Except as provided in paragraph (c)(2) or (3) of this section, the Administrator will not record such TR NO_X Ozone Season allowances under § 97.521.

(2) If the Administrator already recorded such TR NO_X Ozone Season allowances under § 97.521 and if the Administrator makes such determination before making deductions for the source that includes such recipient under § 97.524(b) for such control period, then the Administrator will deduct from the account in which such TR NO_X Ozone Season allowances

were recorded an amount of TR NO_X Ozone Season allowances allocated for the same or a prior control period equal to the amount of such already recorded TR NO_X Ozone Season allowances. The authorized account representative shall ensure that there are sufficient TR NO_X Ozone Season allowances in such account for completion of the deduction.

(3) If the Administrator already recorded such TR NO_X Ozone Season allowances under § 97.521 and if the Administrator makes such determination after making deductions for the source that includes such recipient under § 97.524(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded TR NO_X Ozone Season allowances.

(4) The Administrator will transfer the TR NO_X Ozone Season allowances that are not recorded, or that are deducted, in accordance with paragraphs (c)(1) and (2) of this section to the new unit set-aside, for the State in which such recipient is located, for the control period in the year of such transfer if the notice required in paragraph (b)(1) of this section for the control period in that year has not been promulgated or, if such notice has been promulgated, in the next year.

§ 97.512 TR NO_X Ozone Season allowance allocations for new units.

(a) For each control period in 2012 and thereafter, the Administrator will allocate, in accordance with the following procedures, TR NO_X Ozone Season allowances to TR NO_X Ozone Season units in a State that are not listed in appendix A to this subpart, to TR NO_X Ozone Season units that are so listed and whose allocation of NO_X Ozone Season allowances for such control period is covered by § 97.511(c)(1) or (2), and to TR NO_X Ozone Season units that are so listed and, pursuant to § 97.511(a)(2), are not allocated TR NO_X Ozone Season allowances for such control period but that operate during the immediately preceding control period:

(1) The Administrator will establish a separate new unit set-aside for each State for each control period in a given year. Each new unit set-aside will be allocated TR NO_X Ozone Season allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.510(a). Each new unit set-aside will be allocated additional TR NO_X Ozone Season allowances in accordance with § 97.511(a)(2) and (c)(4).

(2) The designated representative of such TR NO_X Ozone Season unit may submit to the Administrator a request, in a format prescribed by the Administrator, to be allocated TR NO_X Ozone Season allowances for a control period, starting with the later of the control period in 2012, the first control period after the control period in which the TR NO_X Ozone Season unit commences commercial operation (for a unit not listed in appendix A to this subpart), or the first control period after the control period in which the unit resumes operation (for a unit listed in appendix A of this subpart) and for each subsequent control period.

(i) The request must be submitted on or before February 1 immediately preceding the first control period for which TR NO_X Ozone Season allowances are sought and after the date on which the TR NO_X Ozone Season unit commences commercial operation (for a unit not listed in appendix A of this subpart) or on which the unit resumes operation (for a unit listed in appendix A of this subpart).

(ii) For each control period for which an allocation is sought, the request must be for TR NO_X Ozone Season allowances in an amount equal to the unit's total tons of NO_X emissions during the immediately preceding control period.

(3) The Administrator will review each TR NO_X Ozone Season allowance allocation request under paragraph (a)(2) of this section and will accept the request only if it meets the requirements of paragraph (a)(2) of this section. The Administrator will allocate TR NO_X Ozone Season allowances for each control period pursuant to an accepted request as follows:

(i) After February 1 immediately preceding such control period, the Administrator will determine the sum of the TR NO_X Ozone Season allowances requested in all accepted allowance allocation requests for such control period.

(ii) If the amount of TR NO_X Ozone Season allowances in the new unit set-aside for such control period is greater than or equal to the sum under paragraph (a)(3)(i) of this section, then the Administrator will allocate the amount of TR NO_X Ozone Season allowances requested to each TR NO_X Ozone Season unit covered by an accepted allowance allocation request.

(iii) If the amount of TR NO_X Ozone Season allowances in the new unit set-aside for such control period is less than the sum under paragraph (a)(3)(i) of this section, then the Administrator will allocate to each TR NO_X Ozone Season unit covered by an accepted allowance allocation request the amount of the TR NO_X Ozone Season allowances requested, multiplied by the amount of TR NO_X Ozone Season allowances in the new unit set-aside for such control period, divided by the sum determined under paragraph (a)(3)(i) of this section, and rounded to the nearest allowance.

(iv) The Administrator will notify, through the promulgation of the notices of data availability described in § 97.511(b), each designated representative that submitted an allowance allocation request of the amount of TR NO_X Ozone Season allowances (if any) allocated for such control period to the TR NO_X Ozone Season unit covered by the request.

(b) If, after completion of the procedures under paragraph (a)(4) of this section for a control period, any unallocated TR NO_X Ozone Season allowances remain in the new unit set-aside under paragraph (a) of this section for a State for such control period, the Administrator will allocate to each TR NO_X Ozone Season unit that is in the State, is listed in appendix A to this subpart, and continues to be allocated TR NO_X Ozone Season allowances for such control period in accordance with § 97.511(a)(2), an amount of TR NO_X Ozone Season allowances equal to the following: The total amount of such remaining unallocated TR NO_X Ozone Season allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.511(a) for such control period, divided by the remainder of the amount of tons in the applicable State NO_X Ozone Season trading budget minus the amount of tons in such new unit set-aside, and rounded to the nearest allowance.

§ 97.513 Authorization of designated representative and alternate designated representative.

(a) Except as provided under § 97.515, each TR NO_X Ozone Season source, including all TR NO_X Ozone Season units at the source, shall have one and only one designated representative, with regard to all matters under the TR NO_X Ozone Season Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR NO_X Ozone Season units at the source and shall act in accordance with the certification statement in § 97.516(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.516:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each TR NO_X Ozone Season unit at the source in all matters pertaining to the TR NO_X Ozone Season Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under § 97.515, each TR NO_X Ozone Season source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR NO_X Ozone Season units at the source and shall act in accordance with the certification statement in § 97.516(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.516,

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit.

(c) Except in this section, § 97.502, and §§ 97.514 through 97.518, whenever the term "designated representative" is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 97.514 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under § 97.518 concerning delegation of authority to make submissions, each submission under the TR NO_X Ozone Season Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each TR NO_X Ozone Season source and TR NO_X Ozone Season unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or 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."

(b) The Administrator will accept or act on a submission made for a TR NO_X Ozone Season source or a TR NO_X Ozone Season unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 97.518.

§ 97.515 Changing designated representative and alternate designated representative; changes in owners and operators.

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.516. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the TR NO_X Ozone Season source and the TR NO_X Ozone Season units at the source.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.516. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the TR NO_X Ozone Season source and the TR NO_X Ozone Season units at the source.

(c) *Changes in owners and operators.* (1) In the event an owner or operator of a TR NO_X Ozone Season source or a TR NO_X Ozone Season unit is not included in the list of owners and operators in the certificate of representation under § 97.516, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a TR NO_X Ozone Season source or a TR NO_X Ozone Season unit, including the addition of a new owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under § 97.516 amending the list of owners and operators to include the change.

§ 97.516 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the TR NO_X Ozone Season source, and each TR NO_X Ozone Season unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe rounded to the nearest tenth) of each generator served by each such unit, and actual or projected date of commencement of commercial operation.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the TR NO_X Ozone Season source and of each TR NO_X Ozone Season unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) "I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each TR NO_X Ozone Season unit at the source."

(ii) "I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR NO_X Ozone Season Trading Program on behalf of the owners and operators of the source and of each TR NO_X Ozone Season 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 order issued to me by the Administrator regarding the source or unit."

(iii) "Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a TR NO_X Ozone Season unit, or where a utility or industrial customer purchases power from a TR NO_X Ozone Season unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each TR NO_X Ozone Season unit at the source; and TR NO_X Ozone Season allowances and proceeds of transactions involving TR NO_X Ozone Season allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of TR NO_X Ozone Season allowances by contract, TR NO_X Ozone Season allowances and proceeds of transactions involving TR NO_X Ozone Season allowances will be deemed to be held or distributed in accordance with the contract."

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.517 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under § 97.516 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 97.516 is received by the Administrator.

(b) Except as provided in § 97.515(a) or (b), no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the TR NO_X Ozone Season Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of TR NO_X Ozone Season allowance transfers.

§ 97.518 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.518(d) shall be deemed to be an electronic submission by me."

(ii) "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.518(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.518 is terminated.".

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

§ 97.519 [Reserved]

§ 97.520 Establishment of Allowance Management System accounts.

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under § 97.516, the Administrator will establish a compliance account for the TR NO_X Ozone Season source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *General accounts*—(1) *Application for general account.* (i) Any person may apply to open a general account, for the purpose of holding and transferring TR NO_X Ozone Season allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to TR NO_X Ozone Season allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the TR NO_X Ozone Season allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to TR NO_X Ozone Season allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR NO_X Ozone Season 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 regarding the general account."

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of authorized account representative and alternate authorized account representative.* (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to TR NO_X Ozone Season allowances held in the general account in all matters pertaining to the TR NO_X Ozone Season Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to TR NO_X Ozone Season allowances held in the general account shall be bound by any order or decision issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (b)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to TR NO_X Ozone Season allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the TR NO_X Ozone Season 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."

(iii) Except in this section, whenever the term "authorized account representative" is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) *Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.* (i) The authorized account representative of 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 authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the TR NO_X Ozone Season allowances in the general account.

(ii) The alternate authorized account representative of 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 authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the TR NO_X Ozone Season allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to TR NO_X Ozone Season allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to NO_X Ozone Season allowances in the general account, including the addition of a new person, the authorized account representative or any alternate 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 TR NO_X Ozone Season allowances in the general account to include the change.

(4) *Objections concerning authorized account representative and alternate authorized account representative.* (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)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the TR NO_X Ozone Season Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of TR NO_X Ozone Season allowance transfers.

(5) *Delegation by authorized account representative and alternate authorized account representative.* (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (b)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (b)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.520(b)(5)(iv) shall be deemed to be an electronic submission by me."; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.520(b)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.520(b)(5) is terminated.".

(iv) A notice of delegation submitted under paragraph (b)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (b)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (b)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6)(i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted TR NO_X Ozone Season allowance transfer under § 97.522 for any TR NO_X Ozone Season allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no TR NO_X Ozone Season allowance transfers to or from the account for a 12-month period or longer and does not contain any TR NO_X Ozone Season allowances, the Administrator may notify the authorized account representative for the account that the account will be closed after 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 TR NO_X Ozone Season allowance transfer under § 97.522 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

(d) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of an Allowance Management System account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of TR NO_X Ozone Season allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 97.514(a) and 97.518 or paragraphs (b)(2)(ii) and (b)(5) of this section.

§ 97.521 Recordation of TR NO_X Ozone Season allowance allocations.

(a) By September 1, 2011, the Administrator will record in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated for the TR NO_X Ozone Season units at the source in accordance with §§ 97.511(a) for the control periods in 2012, 2013, and 2014.

(b) By June 1, 2012 and June 1 of each year thereafter, the Administrator will record in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated for the TR NO_X Ozone Season units at the source in accordance with § 97.511(a) for the control period in the third year after the year of the applicable recordation deadline under this paragraph.

(c) By June 1, 2012 and June 1 of each year thereafter, the Administrator will record in each TR NO_X Ozone Season source's compliance account the TR NO_X Ozone Season allowances allocated for the TR NO_X Ozone Season units at the source in accordance with § 97.512 for the control period in the year of the applicable recordation deadline under this paragraph.

(d) When recording the allocation of TR NO_X Ozone Season allowances for a TR NO_X Ozone Season unit in a compliance account, the Administrator will assign each TR NO_X Ozone Season allowance a unique identification number that will include digits identifying the year of the control period for which the TR NO_X Ozone Season allowance is allocated.

§ 97.522 Submission of TR NO_X Ozone Season allowance transfers.

(a) An authorized account representative seeking recordation of a TR NO_X Ozone Season allowance transfer shall submit the transfer to the Administrator.

(b) A TR NO_X Ozone Season allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each TR NO_X Ozone Season allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each TR NO_X Ozone Season allowance identified by serial number in the transfer.

§ 97.523 Recordation of TR NO_X Ozone Season allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a TR NO_X Ozone Season allowance transfer, the Administrator will record a TR NO_X Ozone Season allowance transfer by moving each TR NO_X Ozone Season allowance from the transferor account to the transferee account as specified by the request, provided that the transfer is correctly submitted under § 97.522.

(b)(1) A TR NO_X Ozone Season allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any TR NO_X Ozone Season allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 97.524 for the control period immediately before such allowance transfer deadline.

(2) A TR NO_X Ozone Season allowance transfer that is submitted for recordation after the deadline for holding TR NO_X Ozone Season allowances described in § 97.525(b)(5) and that includes any TR NO_X Ozone Season allowances allocated for a control period before the year of such deadline will not be recorded until after the Administrator completes the deductions under § 97.525 for the control period immediately before the year of such deadline.

(c) Where a TR NO_X Ozone Season allowance transfer is not correctly submitted under § 97.522, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a TR NO_X Ozone Season allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a TR NO_X Ozone Season allowance transfer that is not correctly submitted under § 97.522, the Administrator will notify the 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.

§ 97.524 Compliance with TR NO_X Ozone Season emissions limitation.

(a) *Availability for deduction for compliance.* TR NO_X Ozone Season allowances are available to be deducted for compliance with a source's TR NO_X Ozone Season emissions limitation for a control period in a given year only if the TR NO_X Ozone Season allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in the source's compliance account as of the allowance transfer deadline for such control period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 97.523, of TR NO_X Ozone Season allowance transfers submitted by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account TR NO_X Ozone Season allowances available under paragraph (a) of this section in order to determine whether the source meets the TR NO_X Ozone Season emissions limitation for such control period, as follows:

(1) Until the amount of TR NO_X Ozone Season allowances deducted equals the number of tons of total NO_X emissions from all TR NO_X Ozone Season units at the source for such control period; or

(2) If there are insufficient TR NO_X Ozone Season allowances to complete the deductions in paragraph (b)(1) of this section, until no more TR NO_X Ozone Season allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of TR NO_X Ozone Season allowances by serial number.* The authorized account representative for a source's compliance account may request that specific TR NO_X Ozone Season allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the TR NO_X Ozone Season source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR NO_X Ozone Season allowances under paragraph (b) or (d) of this section from the source's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR NO_X Ozone Season allowances in such request, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any TR NO_X Ozone Season allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR NO_X Ozone Season allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Deductions for excess emissions.* After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the TR NO_X Ozone Season source has excess emissions, the Administrator will deduct from the source's compliance account an amount of TR NO_X Ozone Season allowances, allocated for the control period in the immediately following year, equal to two times the number of tons of the source's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.525 Compliance with TR NO_X Ozone Season assurance provisions.

(a) *Availability for deduction.* TR NO_X Ozone Season allowances are available to be deducted for compliance with the TR NO_X Ozone Season assurance provisions for a control period in a given year by an owner of one or more TR NO_X Ozone Season units in a State only if the TR NO_X Ozone Season allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in a compliance account, designated by the owner in accordance with paragraph (b)(4)(ii) of this section, of one of the owner's TR NO_X Ozone Season sources in the State as of the deadline established in paragraph (b)(5) of this section.

(b) *Deductions for compliance.* The Administrator will deduct TR NO_X Ozone Season allowances available under paragraph (a) of this section for compliance with the TR NO_X Ozone Season assurance provisions for a State for a control period in a given year in accordance with the following procedures:

(1) By March 1, 2015 and March 1 of each year thereafter, the Administrator will:

(i) Calculate, separately for each State, the total amount of NO_X emissions from all TR NO_X Ozone Season units in the State during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total amount of NO_X emissions exceeds the State assurance level as described in § 97.506(c)(2)(iii); and

(ii) Promulgate a notice of availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the NO_X emissions for each TR NO_X Ozone Season unit and of the amounts described in §§ 97.506(c)(2)(iii)(A) and (B) for each State.

(2) The Administrator will provide an opportunity for submission of objections to the calculations referenced by each notice described in paragraph (b)(1) of this section.

(i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations for each TR NO_X Ozone Season unit and each State for the control period in the year involved are in accordance with § 97.506(c)(2)(iii) and §§ 97.506(b) and 97.530 through 97.535.

(ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By May 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.

(3) For each notice of data availability required in paragraph (b)(2)(ii) of this section and for any State identified in such notice as having TR NO_X Ozone Season sources with total NO_X emissions exceeding the State assurance level for a control period, as described in § 97.506(c)(2)(iii):

(i) By May 15 immediately after the promulgation of such notice, the designated representative of each TR NO_X Ozone Season source in each such State shall submit a statement, in a format prescribed by the Administrator:

(A) Listing all the owners of each TR NO_X Ozone Season unit at the source, explaining how the selection of each owner for inclusion on the list is consistent with the definition of "owner" in § 97.502, and listing, separately for each unit, the percentage of the legal, equitable, leasehold, or contractual reservation or entitlement for each such owner as of midnight of December 31 of the control period in the year involved; and

(B) For each TR NO_X Ozone Season unit at the source that operates during, but is allocated no TR NO_X Ozone Season allowances for, the control period in the year involved, identifying whether the unit is a coal-fired boiler, simple combustion turbine, or combined cycle turbine cycle and providing the unit's allowable NO_X emission rate for such control period.

(ii) By June 15 immediately after the promulgation of such notice, the Administrator will calculate, for each such State and each owner of one or more TR NO_X Ozone Season units in the State and for the control period in the year involved, each owner's share of the total NO_X emissions from all TR NO_X Ozone Season units in the State, each owner's assurance level, and the amount (if any) of TR NO_X Ozone Season allowances that each owner must hold in accordance with the calculation formula in § 97.506(c)(2)(i) and will promulgate a notice of availability of the results of these calculations.

(iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(3)(ii) of this section.

(A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations for each owner for the control period in the year involved are consistent with the NO_X emissions for the relevant TR NO_X Ozone Season units as set forth in the notice required in paragraph (b)(2)(ii) of this section, the definitions of "owner", "owner's assurance level", and "owner's share" in § 97.502, and the calculation formula in § 97.506(c)(2)(i) and shall not raise any issues about any data used in the notice of data availability required in paragraph (b)(2)(ii) of this section.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are consistent with the data and provisions referenced in paragraph (b)(3)(iii)(A) of this section.

By August 15 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(3)(iii)(A) of this section.

(4) By September 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section:

(i) Each owner identified, in such notice, as owning one or more TR NO_X Ozone Season units in a State and as being required to hold TR NO_X Ozone Season allowances shall designate the compliance account of one of the sources at which such unit or units are located to hold such required TR NO_X Ozone Season allowances;

(ii) The authorized account representative for the compliance account designated under paragraph (b)(4)(i) of this section shall submit to the Administrator a statement, in a format prescribed by the Administrator, making this designation.

(5)(i) As of midnight of September 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section, each owner described in paragraph (b)(4)(i) of this section shall hold in the compliance account designated by the owner in accordance with paragraph (b)(4)(ii) of this section the total amount of TR NO_X Ozone Season allowances, available for deduction under paragraph (a) of this section, equal to the amount the owner is required to hold as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(5)(i) of this section, if September 15 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(6) After September 15 (or the date described in paragraph (b)(5)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section and after the recordation, in accordance with § 97.523, of TR NO_X Ozone Season allowance transfers submitted by midnight of such date, the Administrator will deduct from each compliance account designated in accordance with paragraph (b)(4)(ii) of this section, TR NO_X Ozone Season allowances available under paragraph (a) of this section, as follows:

(i) Until the amount of TR NO_X Ozone Season allowances deducted equals the amount that the owner designating the compliance account is required to hold as calculated by the Administrator and referenced in the notice required in paragraph (b)(3)(iii)(B) of this section; or

(ii) If there are insufficient TR NO_X Ozone Season allowances to complete the deductions in paragraph (b)(6)(i) of this section, until no more TR NO_X Ozone Season allowances available under paragraph (a) of this section remain in the compliance account.

(7) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notices of data availability required in paragraphs (b)(2)(ii) and (b)(3)(iii)(B) of this section respectively for a control period, of any data used in making the calculations referenced in such notice, the amount of TR NO_X Ozone Season allowances that each owner is required to hold in accordance with § 97.506(c)(2)(i) for the control period in the year involved shall continue to be such amount as calculated by the Administrator and referenced in such notice required in paragraph (b)(3)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of TR NO_X Ozone Season allowances that owners are required to hold in accordance with the calculation formula in § 97.506(c)(2)(i) for the control period in the year involved with regard to the State involved, provided that—

(A) With regard to such litigation involving such notice required in paragraph (b)(2)(ii) of this section, such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(ii) of this section; and

(B) With regard to such litigation involving such notice required in paragraph (b)(3)(iii) of this section, such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(3)(iii) of this section.

(ii) If any such data are revised by the owners and operators of a source whose designated representative submitted such data under paragraph (b)(3)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of TR NO_X Ozone Season allowances that owners are required to hold in accordance with the calculation formula in § 97.506(c)(2)(i) for the control period in the year involved with regard to the State involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(3)(iii)(B) of this section.

(iii) If the revised data are used to recalculate, in accordance with paragraphs (b)(7)(i) and (b)(7)(ii) of this section, the amount of TR NO_X Ozone Season allowances that an owner is required to hold for the control period in the year involved with regard to the State involved-

(A) Where the amount of TR NO_X Ozone Season allowances that an owner is required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owner shall hold the additional amount of TR NO_X Ozone Season allowances in the compliance account designated by the owner in accordance with paragraph (b)(4)(ii) of this section. The owner's failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owner's failure to hold such additional amount, as required, as of the new deadline shall be a violation of the Clean Air Act. Each TR NO_X Ozone Season allowance that the owner fails to hold as required as of the new deadline, and each day in the control period in the year involved, shall be a separate violation of the Clean Air Act. After such deadline, the Administrator will make the appropriate deductions from the compliance account.

(B) For an owner for which the amount of TR NO_X Ozone Season allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in the compliance account that the owner designated in accordance with paragraph (b)(4)(ii) of this section, an amount of TR NO_X Ozone Season allowances equal to the amount of the decrease to the extent such amount was previously deducted from the compliance account under paragraph (b)(6) of this section (and has not already been restored to the compliance account) for the control period in the year involved.

(C) Each TR NO_X Ozone Season allowance held and deducted under paragraph (b)(7)(iii)(A) of this section, or recorded under paragraph (b)(7)(iii)(B) of this section, as a result of recalculation of requirements for compliance with the TR NO_X Ozone Season assurance provisions for a control period in a given year must be a TR NO_X Ozone Season allowance allocated for a control period in the same or a prior year.

(c)(1) *Identification of TR NO_X Ozone Season allowances by serial number.* The authorized account representative for each source's compliance account designated in accordance with paragraph (b)(4)(ii) of this section may request that specific TR NO_X Ozone Season allowances, identified by serial number, in the compliance account be deducted in accordance with paragraph (b)(6) or (7) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance-holding deadline described in paragraph (b)(5) of this section and include, in a format prescribed by the Administrator, the identification of the compliance account and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR NO_X Ozone Season allowances under paragraphs (b)(6) and (7) of this section from each source's compliance account designated under paragraph (b)(4)(ii) of this section in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR NO_X Ozone Season allowances in such request, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any TR NO_X Ozone Season allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR NO_X Ozone Season allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraph (b) of this section.

§ 97.526 Banking.

(a) A TR NO_X Ozone Season allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any TR NO_X Ozone Season allowance that is held in a compliance account or a general account will remain in such account unless and until the TR NO_X Ozone Season allowance is deducted or transferred under § 97.511(c), § 97.523, § 97.524, § 97.525, 97.527, 97.528, 97.542, or 97.543.

§ 97.527 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.528 Administrator's action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the TR NO_X Ozone Season Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct TR NO_X Ozone Season allowances from or transfer TR NO_X Ozone Season allowances to a source's compliance account based on the information in a submission, as adjusted under paragraph (a)(1) of this section, and record such deductions and transfers.

§ 97.529 [Reserved]

§ 97.530 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a TR NO_X Ozone Season unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subpart H of part 75 of this chapter. For purposes of applying such requirements, the definitions in § 97.502 and in § 72.2 of this chapter shall apply, the terms "affected unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") in part 75 of this chapter shall be deemed to refer to the terms "TR NO_X Ozone Season unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") respectively as defined in § 97.502, and the term "newly affected unit" shall be deemed to mean "newly affected TR NO_X Ozone Season unit". The owner or operator of a unit that is not a TR NO_X Ozone Season unit but that is monitored under § 75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a TR NO_X Ozone Season unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each TR NO_X Ozone Season unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO_X mass emissions and individual unit heat input (including all systems required to monitor NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under § 97.531 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a TR NO_X Ozone Season unit that commences commercial operation before July 1, 2011, by May 1, 2012.

(2) For the owner or operator of a TR NO_X Ozone Season unit that commences commercial operation on or after July 1, 2011 and that reports on an annual basis under § 97.534(d), by the later of the following dates:

(i) 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation; or

(ii) May 1, 2012.

(3) For the owner or operator of a TR NO_X Ozone Season unit that commences commercial operation on or after July 1, 2011 and that reports on a control period basis under § 97.534(d)(2)(ii), by the later of the following dates:

(i) 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation; or

(ii) If the compliance date under paragraph (b)(3)(i) of this section is not during a control period, May 1 immediately after the compliance date under paragraph (b)(3)(i) of this section.

(4) For the owner or operator of a TR NO_X Ozone Season unit for which

construction of a new stack or flue or installation of add-on NO_X emission controls is completed after the applicable deadline under paragraph (b)(1) or (2) of this section and that reports on an annual basis under § 97.534(d), by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO_X emissions controls.

(5) For the owner or operator of a TR NO_X Ozone Season unit for which construction of a new stack or flue or installation of add-on NO_X emission controls is completed after the applicable deadline under paragraph (b)(1) or (3) of this section and that reports on a control period basis under § 97.534(d)(2)(ii), by the later of the following dates:

(i) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO_X emissions controls; or

(ii) If the compliance date under paragraph (b)(5)(i) of this section is not during a control period, May 1 immediately after the compliance date under paragraph (b)(5)(i) of this section.

(6) Notwithstanding the dates in paragraphs (b)(1), (2), and (3) of this section, for the owner or operator of a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved, by the date specified in § 97.541(c).

(7) Notwithstanding the dates in paragraphs (b)(1), (2), and (3) of this section, for the owner or operator of a TR NO_X Ozone Season opt-in unit, by the date on which the TR NO_X Annual opt-in unit enters the TR NO_X Ozone Season Trading Program as provided in § 97.541(h).

(c) *Reporting data.* The owner or operator of a TR NO_X Ozone Season unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NO_X concentration, NO_X emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NO_X mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(d) *Prohibitions.* (1) No owner or operator of a TR NO_X Ozone Season unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 97.535.

(2) No owner or operator of a TR NO_X Ozone Season unit 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.

(3) No owner or operator of a TR NO_X Ozone Season unit 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 or heat input, 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.

(4) No owner or operator of a TR NO_X Ozone Season unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 97.505 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 Administrator 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 designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 97.531(d)(3)(i).

(e) *Long-term cold storage.* The owner or operator of a TR NO_X Ozone Season unit is subject to the applicable provisions of § 75.4(d) of this chapter concerning units in long-term cold storage.

§ 97.531 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a TR NO_X Ozone Season unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 97.530(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendices B, D, and E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 97.530(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously 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 § 75.12 or § 75.17 of this chapter, the designated representative shall resubmit the petition to the Administrator under § 97.535 to determine whether the approval applies under the TR NO_X Ozone Season Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a TR NO_X Ozone Season unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (*i.e.,* a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under § 97.530(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under § 97.530(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 97.530(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 97.530(a)(1) that may significantly affect the ability of the system to accurately measure or record NO_X mass emissions or heat input rate or to meet the quality-assurance and quality-control 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 in accordance with § 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 may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: Replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter systems, and any excepted NO_X monitoring system under appendix E to part 75 of this chapter, under § 97.530(a)(1) are subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* For initial certification of a continuous monitoring system under § 97.530(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words "certification" and "initial certification" are replaced by the word "recertification" and the word "certified" is replaced by with the word "recertified".

(i) *Notification of certification.* The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with § 97.533.

(ii) *Certification application.* The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the TR NO_X Ozone Season Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, 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 Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) *Certification application approval process.* The Administrator 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 (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that 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 TR NO_X Ozone Season 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 Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period specified in paragraph (d)(3) of this section shall not begin before receipt of a complete certification application.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator 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 Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter).

(D) *Audit decertification.* The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 97.532(b).

(v) *Procedures for loss of certification.* If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(*1*) For a disapproved NO_X emission rate (*i.e.,* NO_X-diluent) system, the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(*2*) For a disapproved NO_X pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NO_X and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(*3*) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(*4*) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(5) For a disapproved excepted NO_X monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 97.532 Monitoring system out-of-control periods.

(*a*) *General provisions.* Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, 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 monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 97.531 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 Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system 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 for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 97.531 for each disapproved monitoring system.

§ 97.533 Notifications concerning monitoring.

The designated representative of a TR NO_X Ozone Season unit shall submit written notice to the Administrator in accordance with § 75.61 of this chapter.

§ 97.534 Recordkeeping and reporting.

(*a*) *General provisions.* The designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements under § 75.73 of this chapter, and the requirements of § 97.514(a).

(*b*) *Monitoring plans.* The owner or operator of a TR NO_X Ozone Season unit shall comply with requirements of § 75.73(c) and (e) of this chapter.

(*c*) *Certification applications.* The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under § 97.531, including the information required under § 75.63 of this chapter.

(*d*) *Quarterly reports.* The designated representative shall submit quarterly reports, as follows:

(1) If the TR NO_X Ozone Season unit is subject to the Acid Rain Program or a TR NO_X Annual emissions limitation or if the owner or operator of such unit chooses to report on an annual basis under this subpart, the designated representative shall meet the requirements of subpart H of part 75 of this chapter (concerning monitoring of NO_X mass emissions) for such unit for the entire year and shall report the NO_X mass emissions data and heat input data for such unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering May 1, 2012 through June 30, 2012;

(ii) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.530(b), unless that quarter is the third or fourth quarter of 2011 or the first quarter of 2012, in which case reporting shall commence in the quarter covering May 1, 2012 through June 30, 2012;

(2) If the TR NO_X Ozone Season unit is not subject to the Acid Rain Program or a TR NO_X Annual emissions limitation, then the designated representative shall either:

(i) Meet the requirements of subpart H of part 75 (concerning monitoring of NO_X mass emissions) for such unit for the entire year and report the NO_X mass emissions data and heat input data for such unit in accordance with paragraph (d)(1) of this section; or

(ii) Meet the requirements of subpart H of part 75 for the control period (including the requirements in § 75.74(c) of this chapter) and report NO_X mass emissions data and heat input data (including the data described in § 75.74(c)(6) of this chapter) for such unit only for the control period of each year and report, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(A) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering May 1, 2012 through June 30, 2012;

(B) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.530(b), unless that date is not during a control period, in which case reporting shall commence in the quarter that includes May 1 through June 30 of the first control period after such date;

(3) Notwithstanding paragraphs (d)(1) and (2) of this section, for a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved, the calendar quarter corresponding to the date specified in § 97.541(c); and

(4) Notwithstanding paragraphs (d)(1) and (2) of this section, for a TR NO_X

Ozone Season opt-in unit, the calendar quarter corresponding to the date on which the TR NO_X Annual opt-in unit enters the TR NO_X Ozone Season Trading Program as provided in § 97.541(h).

(5) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.73(f) of this chapter.

(6) For TR NO_X Ozone Season units that are also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 1 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the NO_X mass emission data, heat input data, and other information required by this subpart.

(7) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(8) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(5) of this section.

(*e*) *Compliance certification.* The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) 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:

(1) 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;

(2) For a unit with add-on NO_X emission controls and for all hours where NO_X 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 quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NO_X emissions; and

(3) For a unit that is reporting on a control period basis under paragraph (d)(2)(ii) of this section, 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.

§ 97.535 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a TR NO_X Ozone Season unit may submit a petition under § 75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§ 97.530 through 97.534 or paragraph (5)(i) or (ii) of the definition of "owner's share" in § 97.502.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(i) Identification of each unit and source covered by the petition;

(ii) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(iii) A description and diagram of any equipment and procedures used in the proposed alternative;

(iv) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be *de minimis;* and

(v) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

§ 97.540 General requirements for TR NO_X Ozone Season opt-in units.

(a) A TR NO_X Ozone Season opt-in unit must be a unit that:

(1) Is located in a State;

(2) Is not a TR NO_X Ozone Season unit under § 97.504;

(3) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect; and

(4) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of this subpart.

(b) A TR NO_X Ozone Season opt-in unit shall be deemed to be a TR NO_X Ozone Season unit for purposes of applying this subpart, except for §§ 97.505, 97.511, and 97.512.

(c) Solely for purposes of applying the requirements of §§ 97.513 through 97.518 and §§ 97.530 through 97.535, a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved under § 97.542 shall be deemed to be a TR NO_X Ozone Season unit.

(d) Any TR NO_X Ozone Season opt-in unit, and any unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved under § 97.542, located at the same source as one or more TR NO_X Ozone Season units shall have the same designated representative and alternate designated representative as such TR NO_X Ozone Season units.

§ 97.541 Opt-in process.

A unit meeting the requirements for a TR NO_X Ozone Season opt-in unit in § 97.540(a) may become a TR NO_X Ozone Season opt-in unit only if, in accordance with this section, the designated representative of the unit submits a complete TR opt-in application for the unit and the Administrator approves the application.

(a) *Applying to opt-in.* The designated representative of the unit may submit a complete TR opt-in application for the unit at any time, except as provided under § 97.542(e). A complete TR opt-in application shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the unit and the source where the unit is located,

including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, and unit identification number and type;

(2) A certification that the unit:

(i) Is not a TR NO_X Ozone Season unit under § 97.504;

(ii) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(iii) Vents all of its emissions to a stack; and

(iv) Has documented heat input (greater than 0 mmBtu) for more than 876 hours during the 6 months immediately preceding submission of the TR opt-in application;

(3) A monitoring plan in accordance with §§ 97.530 through 97.535;

(4) A statement that the unit, if approved to become a TR NO_X Ozone Season unit under paragraph (g) of this section, may withdraw from the TR NO_X Ozone Season Trading Program only in accordance with § 97.542;

(5) A statement that the unit, if approved to become a TR NO_X Ozone Season unit under paragraph (g) of this section, is subject to, and the owners and operators of the unit must comply with, the requirements of § 97.543;

(6) A complete certificate of representation under § 97.516 consistent with § 97.540, if no designated representative has been previously designated for the source that includes the unit; and

(7) The signature of the designated representative and the date signed.

(b) *Interim review of monitoring plan.* The Administrator will determine, on an interim basis, the sufficiency of the monitoring plan submitted under paragraph (a)(3) of this section. The monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the NO_X emission rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with §§ 97.530 through 97.535. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(c) *Monitoring and reporting.* (1)(i) If the Administrator determines that the monitoring plan is sufficient under paragraph (b) of this section, the owner or operator of the unit shall monitor and report the NO_X emission rate and the heat input of the unit and all other applicable parameters, in accordance with §§ 97.530 through 97.535, starting on the date of certification of the necessary monitoring systems under §§ 97.530 through 97.535 and continuing until the TR opt-in application submitted under paragraph (a) of this section is disapproved under this section or, if such TR opt-in application is approved, the date and time when the unit is withdrawn from the TR NO_X Ozone Season Trading Program in accordance with § 97.542.

(ii) The monitoring and reporting under paragraph (c)(1)(i) of this section shall cover the entire control period immediately before the date on which the unit enters the TR NO_X Ozone Season Trading Program under paragraph (h) of this section, during which period monitoring system availability must not be less than 98 percent under §§ 97.530 through 97.535 and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the NO_X emissions rate and the heat input of the unit are monitored and reported in accordance with §§ 97.530 through 97.535 for one or more entire control periods, in addition to the control period under paragraph (c)(1)(ii) of this section, during which control periods monitoring system availability is not less than 98 percent under §§ 97.530 through 97.535 and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the TR NO_X Ozone Season Trading Program under paragraph (h) of this section, such information shall be used as provided in paragraphs (e) and (f) of this section.

(d) *Statement on compliance.* After submitting to the Administrator all quarterly reports required for the unit under paragraph (c) of this section, the designated representative shall submit, in a format prescribed by the Administrator, to the Administrator a statement that, for the years covered by such quarterly reports, the unit was in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(e) *Baseline heat input.* The unit's baseline heat input shall equal:

(1) If the unit's NO_X emissions rate and heat input are monitored and reported for only one entire control period, in accordance with paragraph (c) of this section, the unit's total heat input (in mmBtu) for such control period; or

(2) If the unit's NO_X emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, the average of the amounts of the unit's total heat input (in mmBtu) for such control periods.

(f) *Baseline NO_X emission rate.* The unit's baseline NO_X emission rate shall equal:

(1) If the unit's NO_X emission rate and heat input are monitored and reported for only one entire control period, in accordance with paragraph (c) of this section, the unit's NO_X emission rate (in lb/mmBtu) for such control period;

(2) If the unit's NO_X emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, and the unit does not have add-on NO_X emission controls during any such control periods, the average of the amounts of the unit's NO_X emission rate (in lb/mmBtu) for such control periods; or

(3) If the unit's NO_X emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, and the unit has add-on NO_X emission controls during any such control periods, the average of the amounts of the unit's NO_X emission rate (in lb/mmBtu) for such control periods during which the unit has add-on NO_X emission controls.

(g) *Review of TR opt-in application.*

(1) After the designated representative submits the complete TR opt-in application, quarterly reports, and statement required in paragraphs (a), (c), and (d) of this section and if the Administrator determines that the designated representative shows that the unit meets the requirements for a TR NO_X Ozone Season opt-in unit in § 97.540, the element certified in paragraph (a)(2)(iv) of this section, and the monitoring and reporting requirements of paragraph (c) of this section, the Administrator will issue a written approval of the TR opt-in application for the unit. The written approve will state the unit's baseline heat input and baseline NO_X emission rate. The Administrator will thereafter establish a compliance account for the source that includes the unit unless the source already has a compliance account.

(2) Notwithstanding paragraphs (a) through (f) of this section, if, at any time before the TR opt-in application is approved under paragraph (g)(1) of this section, the Administrator determines that the unit cannot meet the requirements for a TR NO_X Ozone Season opt-in unit in § 97.540, the element certified in paragraph (a)(2)(iv) of this section, or the monitoring and reporting requirements in paragraph (c) of this section, the Administrator will issue a written disapproval of the TR opt-in application for the unit.

(h) Date of entry into TR NO_X Ozone Season Trading Program. A unit for which a TR opt-in application is approved under paragraph (g)(1) of this section shall become a TR NO_X Ozone Season opt-in unit, and a TR NO_X Ozone Season unit, effective as of the later of May 1, 2012 or May 1 of the first control period during which such approval is issued.

§ 97.542 Withdrawal of TR NO_X Ozone Season opt-in unit from TR NO_X Ozone Season Trading Program.

A TR NO_X Ozone Season opt-in unit may withdraw from the TR NO_X Ozone Season Trading Program only if, in accordance with this section, the designated representative of the unit submits a request to withdraw the unit and the Administrator issues a written approval of the request.

(a) *Requesting withdrawal.* In order to withdraw the TR NO_X Ozone Season opt-in unit from the TR NO_X Ozone Season Trading Program, the designated representative of the unit shall submit to the Administrator a request to withdraw the unit effective as of midnight of September 30 of a specified calendar year, which date must be at least 4 years after September 30 of the year of the unit's entry into the TR NO_X Ozone Season Trading Program under § 97.541(h). The request shall be in a format prescribed by the Administrator and shall be submitted no later than 90 days before the requested effective date of withdrawal.

(b) *Conditions for withdrawal.* Before a TR NO_X Ozone Season opt-in unit covered by the request to withdraw may withdraw from the TR NO_X Ozone Season Trading Program, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the TR NO_X Ozone Season opt-in unit must meet the requirement to hold TR NO_X Ozone Season allowances under §§ 97.524 and 97.525 and cannot have any excess emissions.

(2) After the requirement under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the TR NO_X Ozone Season opt-in unit TR NO_X Ozone Season allowances equal in amount to and allocated for the same or a prior control period as any TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season opt-in unit under § 97.544 for any control period after the date on which the withdrawal is to be effective. If there are no other TR NO_X Ozone Season units at the source, the Administrator will close the compliance account, and the owners and operators of the TR NO_X Ozone Season opt-in unit may submit a TR NO_X Ozone Season allowance transfer for any remaining TR NO_X Ozone Season allowances to another Allowance Management System account in accordance §§ 97.522 and 97.523.

(c) *Approving withdrawal.* (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of TR NO_X Ozone Season allowances required), the Administrator will issue a written approval of the request to withdraw, which will become effective as of midnight on September 30 of the calendar year for which the withdrawal was requested. The unit covered by the request shall continue to be a TR NO_X Ozone Season opt-in unit until the effective date of the withdrawal and shall comply with all requirements under the TR NO_X Ozone Season Trading Program concerning any control periods for which the unit is a TR NO_X Ozone Season opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the Administrator will issue a written disapproval of the request to withdraw. The unit covered by the request shall continue to be a TR NO_X Ozone Season opt-in unit.

(d) *Reapplication upon failure to meet conditions of withdrawal.* If the Administrator disapproves the request to withdraw, the designated representative of the unit may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(e) *Ability to reapply to the TR NO_X Ozone Season Trading Program.* Once a TR NO_X Ozone Season opt-in unit withdraws from the TR NO_X Ozone Season Trading Program, the designated representative may not submit another opt-in application under § 97.541 for such unit before the date that is 4 years after the date on which the withdrawal became effective.

§ 97.543 Change in regulatory status.

(a) *Notification.* If a TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504, then the designated representative of the unit shall notify the Administrator in writing of such change in the TR NO_X Ozone Season opt-in unit's regulatory status, within 30 days of such change.

(b) *Administrator's actions.* (1) If a TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504, the Administrator will deduct, from the compliance account of the source that includes the TR NO_X Ozone Season opt-in unit that becomes a TR NO_X Ozone Season unit under § 97.504, TR NO_X Ozone Season allowances equal in amount to and allocated for the same or a prior control period as:

(i) Any TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season opt-in unit under § 97.544 for any control period starting after the date on which the TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504; and

(ii) If the date on which the TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504 is not September 30, the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season opt-in unit under § 97.544 for the control period that includes the date on which the TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504—

(A) Multiplied by the ratio of the number of days, in the control period, starting with the date on which the TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504, divided by the total number of days in the control period, and

(B) Rounded to the nearest allowance.

(2) The designated representative shall ensure that the compliance account of the source that includes the TR NO_X Ozone Season opt-in unit that becomes a TR NO_X Ozone Season unit under § 97.504 contains the TR NO_X Ozone Season allowances necessary for completion of the deduction under paragraph (b)(1) of this section.

(3)(i) For control periods starting after the date on which the TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504, the TR NO_X Ozone Season opt-in unit will be allocated TR NO_X Ozone Season allowances in accordance with § 97.512.

(ii) If the date on which the TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504 is not September 30, the following amount of TR NO_X Ozone Season allowances will be allocated to the TR NO_X Ozone Season opt-in unit (as a TR NO_X Ozone Season unit) in accordance with § 97.512 for the control period that includes the date on which the TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504:

(A) The amount of TR NO_X Ozone Season allowances otherwise allocated to the TR NO_X Ozone Season opt-in unit (as a TR NO_X Ozone Season unit) in accordance with § 97.512 for the control period;

(B) Multiplied by the ratio of the number of days, in the control period, starting with the date on which the TR NO_X Ozone Season opt-in unit becomes a TR NO_X Ozone Season unit under § 97.504, divided by the total number of days in the control period; and

(C) Rounded to the nearest allowance.

§ 97.544 TR NO_X Ozone Season allowance allocations to TR NO_X Ozone Season opt-in units.

(a) *Timing requirements.* (1) When the TR opt-in application is approved for a unit under § 97.541(g), the Administrator will issue TR NO_X Ozone Season allowances and allocate them to the unit for the control period in which the unit enters the TR NO_X Ozone Season Trading Program under § 97.541(h), in accordance with paragraph (b) of this section.

(2) By no later than July 30 of the control period after the control period in which a TR NO_X Ozone Season opt-in unit enters the TR NO_X Ozone Season Trading Program under § 97.541(h) and July 30 of each year thereafter, the Administrator will issue TR NO_X Ozone Season allowances and allocate them to the TR NO_X Ozone Season opt-in unit for the control period that includes such allocation deadline and in which the unit is a TR NO_X Ozone Season opt-in unit, in accordance with paragraph (b) of this section.

(b) *Calculation of allocation.* For each control period for which a TR NO_X Ozone Season opt-in unit is to be allocated TR NO_X Ozone Season allowances, the Administrator will issue and allocate TR NO_X Ozone Season allowances in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the TR NO_X Ozone Season allowance allocation will be the lesser of:

(i) The TR NO_X Ozone Season opt-in unit's baseline heat input determined under § 97.541(g); or

(ii) The TR NO_X Ozone Season opt-in unit's heat input, as determined in accordance with §§ 97.530 through 97.535, for the immediately prior control period, except when the allocation is being calculated for the control period in which the TR NO_X Ozone Season opt-in unit enters the TR NO_X Ozone Season Trading Program under § 97.541(h).

(2) The NO_X emission rate (in lb/mmBtu) used for calculating TR NO_X Ozone Season allowance allocations will be the lesser of:

(i) The TR NO_X Ozone Season opt-in unit's baseline NO_X emission rate (in lb/mmBtu) determined under § 97.541(g) and multiplied by 70 percent; or

(ii) The most stringent State or Federal NO_X emissions limitation applicable to the TR NO_X Ozone Season opt-in unit at any time during the control period for which TR NO_X Ozone Season allowances are to be allocated.

(3) The Administrator will issue TR NO_X Ozone Season allowances and allocate them to the TR NO_X Ozone Season opt-in unit in an amount equaling the heat input under paragraph (b)(1) of this section, multiplied by the NO_X emission rate under paragraph (b)(2) of this section, divided by 2,000 lb/ton, and rounded to the nearest allowance.

(c) *Recordation.* (1) The Administrator will record, in the compliance account of the source that includes the TR NO_X Ozone Season opt-in unit, the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season opt-in unit under paragraph (a)(1) of this section.

(2) By September 1 of the control period after the control period in which a TR NO_X Ozone Season opt-in unit enters the TR NO_X Ozone Season Trading Program under § 97.541(h) and September 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the TR NO_X Ozone Season opt-in unit, the TR NO_X Ozone Season allowances allocated to the TR NO_X Ozone Season opt-in unit under paragraph (a)(2) of this section.

37. Part 97 is amended by adding subpart CCCCC to read as follows:

Subpart CCCCC—TR SO_2 Group 1 Trading Program

Subpart CCCCC—TR SO_2 Group 1 Trading Program

§ 97.601 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Transport Rule (TR) SO_2 Group 1 Trading Program, under section 110 of the Clean Air Act and § 52.38(b) of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

§ 97.602 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor) of the United

States Environmental Protection Agency, the Administrator's duly authorized representative under this subpart.

Allocate or allocation means, with regard to TR SO_2 Group 1 allowances, the determination by the Administrator of the amount of such TR SO_2 Group 1 allowances to be initially credited to a TR SO_2 Group 1 source or a new unit set-aside.

Allowable SO_2 emission rate means, with regard to a unit, the SO_2 emission rate limit that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, deductions, and transfers of TR SO_2 Group 1 allowances under the TR SO_2 Group 1 Trading Program. Such allowances are allocated, held, deducted, or transferred only as whole allowances. The Allowance Management System is a component of the CAMD Business System, which is the system used by the Administrator to handle TR SO_2 Group 1 allowances and data related to SO_2 emissions.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, holding, transfer, or deduction of TR SO_2 Group 1 allowances.

Allowance transfer deadline means, for a control period, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR SO_2 Group 1 allowance transfer must be submitted for recordation in a TR SO_2 Group 1 source's compliance account in order to be available for use in complying with the source's TR SO_2 Group 1 Annual emissions limitation for such control period in accordance with § 97.624.

Alternate designated representative means, for a TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the TR SO_2 Group 1 Trading Program. If the TR SO_2 Group 1 source is also subject to the Acid Rain Program, TR NO_X Annual Season Trading Program, or TR NO_X Ozone Season Trading Program, then this natural person shall be the same natural person as the alternate designated representative as defined in § 72.2 of this chapter, § 97.402, or § 97.502 respectively.

Authorized account representative means, with regard to a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of TR SO_2 Group 1 allowances held in the general account and, with regard to a TR SO_2 Group 1 source's compliance account, the designated representative of the source.

Automated data acquisition and handling system or DAHS means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, 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 this subpart.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

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.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president or the corporation in charge of a principal business function or any other person who performs similar policy or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during 1990 or any year thereafter.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine—

(1) Operating as part of a cogeneration system; and

(2) Producing during the later of 1990 or the 12-month period starting on the date that the unit first produces electricity and during each calendar year after the later of 1990 or the calendar year in which the unit first produces electricity—

(i) For a topping-cycle unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel, except biomass if the unit is a boiler; and

(4) Provided that, if a topping-cycle unit is operated as part of a cogeneration system during a calendar year and the cogeneration system meets on a system-wide basis the requirement in paragraph

(2)(i)(B) of this definition, the topping-cycle unit shall be deemed to meet such requirement during that calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, 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; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) 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 § 97.605.

(i) For a unit that is a TR SO_2 Group 1 unit under § 97.604 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a TR SO_2 Group 1 unit under § 97.604 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 97.605, for a unit that is not a TR SO_2 Group 1 unit under § 97.604 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in introductory text of paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a TR SO_2 Group 1 unit under § 97.604.

(i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Commence operation means, with regard to a unit:

(1) To have begun any mechanical, chemical, or electronic process, including start-up of the unit's combustion chamber.

(2) For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(3) For a unit that is replaced by a unit at the same source after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the replaced unit's date of commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a TR SO_2 Group 1 source under this subpart, in which any TR SO_2 Group 1 allowance allocations for the TR SO_2 Group 1 units at the source are recorded and in which are held any TR SO_2 Group 1 allowances available for use for a control period in complying with the source's TR SO_2 Group 1 emissions limitation in accordance with § 97.624 and the TR SO_2 Group 1 assurance provisions in accordance with § 97.625.

Continuous emission monitoring system or CEMS means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of SO_2 emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 or CO_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§ 97.630 through 97.635. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A SO_2 monitoring system, consisting of a SO_2 pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of SO_2 emissions, in parts per million (ppm);

(3) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(4) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(5) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period starting January 1 of a calendar year, except as provided in § 97.606(c)(3), and ending on December 31 of the same year, inclusive.

Designated representative means, for a TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the TR SO_2 Group 1 Trading Program. If the TR SO_2 Group 1 source is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, or TR NO_X Ozone Season Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in § 72.2 of this chapter, § 97.402, or § 97.502 respectively.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart.

Excess emissions means any ton of SO_2 emitted from the TR SO_2 Group 1 units at a TR SO_2 Group 1 source during a control period that exceeds the TR SO_2 Group 1 emissions limitation for the source.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying §§ 97.604(b)(2)(i)(B), 97.604(b)(2)(ii)(B), and 97.604(b)(2)(iii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 1990 or any calendar year thereafter.

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a unit for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

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 generated by 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 no less 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 maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

Newly affected TR SO_2 Group 1 unit means a unit that was not a TR SO_2 Group 1 unit when it began operating but that thereafter becomes a TR SO_2 Group 1 unit.

Operate or operation means, with regard to a unit, to combust fuel.

Operator means any person who operates, controls, or supervises a TR SO_2 Group 1 unit or a TR SO_2 Group 1 source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means, with regard to a TR SO_2 Group 1 source or a TR SO_2 Group 1 unit at a source respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a TR SO_2 Group 1 unit at the source or the TR SO_2 Group 1 unit;

(2) Any holder of a leasehold interest in a TR SO_2 Group 1 unit at the source or the TR SO_2 Group 1 unit, provided that, 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) on the revenues or income from such TR SO_2 Group 1 unit;

(3) Any purchaser of power from a TR SO_2 Group 1 unit at the source or the TR SO_2 Group 1 unit under a life-of-the-unit, firm power contractual arrangement;

(4) Provided that, for purposes of applying the TR SO_2 Group 1 assurance provisions in §§ 97.606(c)(2) and 97.625, if one or more owners (as defined in paragraphs (1) through (3) of this definition) of one or more TR SO_2 Group 1 units in a State are wholly owned by another, common owner, all such owners shall be treated collectively as a single owner in the State.

Owner's assurance level means:

(1) With regard to a State and control period for which the State assurance level is exceeded as described in § 97.606(c)(2)(iii)(A) and not as described in § 97.606(c)(2)(iii)(B), the owner's share of the State SO_2 Group 1 trading budget with the one-year variability limit for the State for such control period; or

(2) With regard to a State and control period for which the State assurance level is exceeded as described in § 97.606(c)(2)(iii)(B), the owner's share of the State SO_2 Group 1 trading budget with the three-year variability limit for the State for such control period.

Owner's share means:

(1) With regard to a total amount of SO_2 emissions from all TR SO_2 Group 1 units in a State during a control period, the total tonnage of SO_2 emissions during such control period from all of the owner's TR SO_2 Group 1 units in the State;

(2) With regard to a State SO_2 Group 1 trading budget with a one-year variability limit for a control period, the

amount (rounded to the nearest allowance) equal to the total amount of TR SO_2 Group 1 allowances allocated for such control period to all of the owner's TR SO_2 Group 1 units in the State, multiplied by the sum of the State SO_2 Group 1 trading budget under § 97.610(a) and the State's one-year variability limit under § 97.610(b) and divided by such State SO_2 Group 1 trading budget;

(3) With regard to a State SO_2 Group 1 trading budget with a three-year variability limit for a control period, the amount (rounded to the nearest allowance) equal to the total amount of TR SO_2 Group 1 allowances allocated for such control period to all of the owner's TR SO_2 Group 1 units in the State, multiplied by the sum of the State SO_2 Group 1 trading budget under § 97.610(a) and the State's three-year variability limit under § 97.610(b) and divided by such State SO_2 Group 1 trading budget;

(4) Provided that, in the case of a unit with more than one owner, the amount of tonnage of SO_2 emissions and of TR SO_2 Group 1 allowances allocated for a control period, with regard to such unit, used in determining each owner's share shall be the amount (rounded to the nearest ton and the nearest allowance) equal to the unit's SO_2 emissions and allocation of such allowances, respectively, for such control period multiplied by the percentage of ownership in the unit that the owner's legal, equitable, leasehold, or contractual reservation or entitlement in the unit comprises as of December 31 of such control period;

(5) Provided that, where two or more units emit through a common stack that is the monitoring location from which SO_2 mass emissions are reported for a control period for a year, the amount of tonnage of each unit's SO_2 emissions used in determining each owner's share for such control period shall be:

(i) The amount (rounded to the nearest ton) of SO_2 emissions reported at the common stack multiplied by the quotient of such unit's heat input for such control period divided by the total heat input reported from the common stack for such control period;

(ii) An amount determined in accordance with a methodology that the Administrator determines is consistent with the purposes of this definition and whose adverse effect (if any) the Administrator determines will be *de minimis;* or

(iii) An amount approved by the Administrator in response to a petition for an alternative requirement submitted in accordance with § 97.635; and

(6) Provided that, in the case of a unit that operates during, but is allocated no TR SO_2 Group 1 allowances for, a control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of TR SO_2 Group 1 allowances for such control period equal to the lesser of—

(i) The unit's allowable SO_2 emission rate (in lb per MWe) applicable to such control period, multiplied by a capacity factor of 0.84 (if the unit is a coal-fired boiler), 0.15 (if the unit is a simple combustion turbine), or 0.66 (if the unit is a combined cycle turbine), multiplied by the unit's maximum hourly load as reported in accordance with this subpart and by 8,760 hours/control period, and divided by 2,000 lb/ton; or

(ii) For a unit listed in appendix A to this subpart, the sum of the unit's SO_2 emissions in the control period in the last three years during which the unit operated during the control period, divided by three.

Permanently retired means, with regard to a unit, a unit that is unavailable for service and that the unit's owners and operators do not expect to return to service in the future.

Permitting authority means "permitting authority" as defined in §§ 70.2 and 71.2 of this chapter.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to TR SO_2 Group 1 allowances, the moving of TR SO_2 Group 1 allowances by the Administrator into, out of, or between Allowance Management System accounts, 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 § 75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

(1) For a topping-cycle unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle unit, the use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a TR SO_2 Group 1 allowance, the unique identification number assigned to each TR SO_2 Group 1 allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a "solid waste incineration unit" as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of "major source", "stationary source", or "source" as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States or the District of Columbia that is subject to the TR SO_2 Group 1 Trading Program pursuant to § 52.38(b) of this chapter.

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;

(4) Provided that compliance with any "submission" or "service" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Topping-cycle unit means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means total energy of all forms supplied to a unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

$$LHV = HHV - 10.55(W + 9H)$$

Where:

LHV = lower heating value of the form of energy in Btu/lb,

HHV = higher heating value of the form of energy in Btu/lb,
W = weight % of moisture in the form of energy, and
H = weight % of hydrogen in the form of energy.

Total energy output means the sum of useful power and useful thermal energy produced by the unit.

TR NO_X Annual Trading Program means a multi-state NO_X air pollution control and emission reduction program established by the Administrator in accordance with subpart AAAAA and 52.37(a) of this chapter, as a means of mitigating interstate transport of fine particulates and NO_X.

TR NO_X Ozone Season Trading Program means a multi-state NO_X air pollution control and emission reduction program established by the Administrator in accordance with subpart BBBBB of this part and 52.37(b) of this chapter, as a means of mitigating interstate transport of ozone and NO_X.

TR SO_2 Group 1 allowance means a limited authorization issued and allocated by the Administrator under this subpart to emit one ton of SO_2 during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the TR SO_2 Group 1 Trading Program.

TR SO_2 Group 1 allowance deduction or deduct TR SO_2 Group 1 allowances means the permanent withdrawal of TR SO_2 Group 1 allowances by the Administrator from a compliance account, *e.g.,* in order to account for compliance with the TR SO_2 Group 1 emissions limitation or assurance provisions.

TR SO_2 Group 1 allowances held or hold TR SO_2 Group 1 allowances means the TR SO_2 Group 1 allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, TR SO_2 Group 1 allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, TR SO_2 Group 1 allowance transfer in accordance with this subpart.

TR SO_2 Group 1 emissions limitation means, for a TR SO_2 Group 1 source, the tonnage of SO_2 emissions authorized in a control period by the TR SO_2 Group 1 allowances available for deduction for the source under § 97.624(a) for such control period.

TR SO_2 Group 1 source means a source that includes one or more TR SO_2 Group 1 units.

TR SO_2 Group 1 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established by the Administrator in accordance with this subpart and 52.38(b) of this chapter, as a means of mitigating interstate transport of fine particulates and SO_2.

TR SO_2 Group 1 unit means a unit that is subject to the TR SO_2 Group 1 Trading Program under § 97.604.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or hour of unit operation means an hour in which a unit combusts any fuel.

Useful power means electricity or mechanical energy that a unit makes available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (e.g., space heating or domestic hot water heating); or

(3) Used in a space cooling application (i.e., in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 97.603 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit
CO_2—carbon dioxide
H_2O—water
hr—hour
kW—kilowatt electrical
kWh—kilowatt hour
lb—pound
mmBtu—million Btu
MWe—megawatt electrical
MWh—megawatt hour
NO_X—nitrogen oxides
O_2—oxygen
ppm—parts per million
scfh—standard cubic feet per hour
SO_2—sulfur dioxide
yr—year

§ 97.604 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State shall be TR SO_2 Group 1 units, and any source that includes one or more such units shall be a TR SO_2 Group 1 source, subject to the requirements of this subpart: Any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a TR SO_2 Group 1 unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a TR SO_2 Group 1 unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State that otherwise is a TR SO_2 Group 1 unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i), (b)(2)(i), or (b)(2)(ii) of this section shall not be a TR SO_2 Group 1 unit:

(1)(i) Any unit:

(A) Qualifying as a cogeneration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If a unit qualifies as a cogeneration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (b)(1)(i) of this section for at least one calendar year, but subsequently no longer meets such qualification and requirements, the unit shall become a TR SO_2 Group 1 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section.

(2)(i) Any unit commencing operation before January 1, 1985:

(A) Qualifying as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit; and

(B) With an average annual fuel consumption of fossil fuel for 1985–1987 less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years after 1990 less than 20 percent (on a Btu basis).

(ii) Any unit commencing operation on or after January 1, 1985:

(A) Qualifying as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit; and

(B) With an average annual fuel consumption of fossil fuel for the first 3 calendar years of operation less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years after 1990 less than 20 percent (on a Btu basis).

(iii) If a unit qualifies as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraph (b)(2)(i) or (ii) of this section for at least 3 consecutive calendar years, but subsequently no longer meets such qualification and requirements, the unit shall become a TR SO_2 Group 1 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 1990 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more.

(c) A certifying official of an owner or operator of any unit or other equipment may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR SO_2 Group 1 Trading Program to the unit or other equipment.

(1) *Petition content.* The petition shall be in writing and include the identification of the unit or other equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: "I am authorized to make this submission on behalf of the owners and operators of the unit or other equipment 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) *Response.* The Administrator will issue a written response to the petition and may request supplemental information determined by the Administrator to be relevant to such petition. The Administrator's determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR SO_2 Group 1 Trading Program to the unit or other equipment shall be binding on any permitting authority unless the Administrator determines that the petition or other documents or information provided in connection with the petition contained significant, relevant errors or omissions.

§ 97.605 Retired unit exemption.

(a)(1) Any TR SO_2 Group 1 unit that is permanently retired and is not a TR SO_2 Group 1 opt-in unit shall be exempt from § 97.606(b) and (c)(1), § 97.624, and §§ 97.630 through 97.635.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the TR SO_2 Group 1 unit is permanently retired. Within 30 days of the unit's permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of 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 before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the TR SO_2 Group 1 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 exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

§ 97.606 Standard requirements.

(a) *Designated representative requirements.* The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§ 97.613 through 97.618.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of each TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.630 through 97.635.

(2) The emissions data determined in accordance with §§ 97.630 through 97.635 shall be used to calculate allocations of TR SO_2 Group 1 allowances under §§ 97.611(a)(2) and (b) and 97.612 and to determine compliance with the TR SO_2 Group 1 emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) *SO_2 emissions requirements*—(1) *TR SO_2 Group 1 emissions limitation.* (i) As of the allowance transfer deadline for a control period, the owners and operators of each TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall hold, in the source's compliance account, TR SO_2 Group 1 allowances available for deduction for such control period under § 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all TR SO_2 Group 1 units at the source.

(ii) If a TR SO_2 Group 1 source emits SO_2 during any control period in excess of the TR SO_2 Group 1 emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall hold the TR SO_2 Group 1 allowances required for deduction under § 97.624(d) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act; and

(B) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) *TR SO_2 Group 1 assurance provisions.* (i) If the total amount of SO_2 emissions from all TR SO_2 Group 1 units in a State during a control period in 2014 or any year thereafter exceeds the State assurance level as described in paragraph (c)(2)(iii) of this section, then each owner whose share of such SO_2 emissions during such control period exceeds the owner's assurance level for the State and such control period shall hold, in a compliance account designated by the owner in accordance with § 97.625(b)(4)(ii), TR SO_2 Group 1 allowances available for deduction for such control period under § 97.625(a) in an amount equal to the product, as determined by the Administrator in accordance with § 97.625(b), of multiplying—

(A) The quotient (rounded to the nearest whole number) of the amount by which the owner's share of such SO_2 emissions exceeds the owner's assurance level divided by the sum of the amounts, determined for all such owners, by which each owner's share of such SO_2 emissions exceeds that owner's assurance level; and

(B) The amount by which total SO_2 emissions for all TR SO_2 Group 1 units in the State for such control period exceed the State assurance level as determined in accordance with paragraph (c)(2)(iii) of this section.

(ii) The owner shall hold the TR SO_2 Group 1 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) The total amount of SO_2 emissions from all TR SO_2 Group 1 units in a State during a control period in 2014 or any year thereafter exceeds the State assurance level:

(A) If such total amount of SO_2 emissions exceeds the sum, for such control period, of the State SO_2 Group 1 trading budget and the State's one-year variability limit under § 97.610(b); or

(B) If, with regard to a control period in 2016 or any year thereafter, the sum, divided by three, of such total amount of SO_2 emissions and the total amounts of SO_2 emissions from all TR SO_2 Group 1 units in the State during the control periods in the immediately preceding two years exceeds the sum, for such control period, of the State SO_2 Group 1 trading budget and the State's three-year variability limit under § 97.610(b);

(C) Provided that the amount by which such total amount of SO_2 emissions exceeds the State assurance level shall be the greater of the amounts of the exceedance calculated under paragraph (c)(2)(iii)(A) of this section and under paragraph (c)(2)(iii)(B) of this section.

(iv) It shall not be a violation of this subpart or of the Clean Air Act if the total amount of SO_2 emissions from all TR SO_2 Group 1 units in a State during a control period exceeds the State assurance level or if an owner's share of total SO_2 emissions from the TR SO_2 Group 1 units in a State during a control period exceeds the owner's assurance level.

(v) To the extent an owner fails to hold TR SO_2 Group 1 allowances for a control period in accordance with paragraphs (c)(2)(i) and (ii) of this section,

(A) The owner shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR SO_2 Group 1 allowance that the owner fails to hold for a control period in accordance with paragraphs (c)(2)(i) and (ii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) *Compliance periods.* A TR SO_2 Group 1 unit shall be subject to the requirements:

(i) Under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2012 or the deadline for meeting the unit's monitor certification requirements under § 97.630(b) and for each control period thereafter; and

(ii) Under paragraph (c)(2) of this section for the control period starting on the later of January 1, 2014 or the deadline for meeting the unit's monitor certification requirements under § 97.630(b) and for each control period thereafter.

(4) *Vintage of deducted allowances.* A TR SO_2 Group 1 allowance shall not be deducted, for compliance with the requirements under paragraphs (c)(1) and (2) of this section, for a control period in a calendar year before the year for which the TR SO_2 Group 1 allowance was allocated.

(5) *Allowance Management System requirements.* Each TR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) *Limited authorization.* (i) A TR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 in accordance with the TR SO_2 Group 1 Trading Program.

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) *Property right.* A TR SO_2 Group 1 allowance does not constitute a property right.

(d) *Title V Permit requirements.* (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR SO_2 Group 1 allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report SO_2 emissions using a continuous emission monitoring system (under §§ 75.10, 75.11, and 75.16 of this chapter), an excepted monitoring system (under appendix D to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.630 through 97.635 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor

permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) *Additional recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of each TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 97.616 for the designated representative for the source and each TR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; 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 certificate of representation under § 97.616 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR SO_2 Group 1 Trading Program, including any monitoring plans and monitoring system certification and recertification applications.

(2) The designated representative of a TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall make all submissions required under the TR SO_2 Group 1 Trading Program, including any submissions required for compliance with the TR SO_2 Group 1 assurance provisions. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) *Liability.* (1) Any provision of the TR SO_2 Group 1 Trading Program that applies to a TR SO_2 Group 1 source or the designated representative of a TR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the TR SO_2 Group 1 units at the source.

(2) Any provision of the TR SO_2 Group 1 Trading Program that applies to a TR SO_2 Group 1 unit or the designated representative of a TR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the TR SO_2 Group 1 Trading Program or exemption under § 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR SO_2 Group 1 source or TR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 97.607 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the TR SO_2 Group 1 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 TR SO_2 Group 1 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 TR SO_2 Group 1 Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 97.608 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the TR SO_2 Group 1 Trading Program are set forth in part 78 of this chapter.

§ 97.609 [Reserved]

§ 97.610 State SO_2 Group 1 trading budgets, new-unit set-asides, and variability limits.

(a) The State SO_2 Group 1 trading budgets and new-unit set-asides for allocations of TR SO_2 Group 1 allowances for the control periods in 2012 and thereafter are as follows:

State	SO_2 Group 1 trading budget (tons) *		New-unit set-aside (tons)	
	For 2012–2013	For 2014 and thereafter	For 2012–2013	For 2014 and thereafter
Georgia	233,260	85,717	6,998	2,572
Illinois	208,957	151,530	6,269	4,546
Indiana	400,378	201,412	12,011	6,042
Iowa	94,052	86,088	2,822	2,583
Kentucky	219,549	113,844	6,586	3,415
Michigan	251,337	155,675	7,540	4,670
Missouri	203,689	158,764	6,111	4,763
New York	66,542	42,041	1,996	1,261
North Carolina	111,485	81,859	3,345	2,456
Ohio	464,964	178,307	13,949	5,349
Pennsylvania	388,612	141,693	11,658	4,251
Tennessee	100,007	100,007	3,000	3,000
Virginia	72,595	40,785	2,178	1,224
West Virginia	205,422	119,016	6,163	3,570
Wisconsin	96,439	66,683	2,893	2,000
Total	3,117,288	1,723,421	93,519	51,703

* Without variability limits.

(b) The States' one-year and three-year variability limits for the State SO_2 Group 1 trading budgets for the control periods in 2014 and thereafter are as follows:

State	One-year variability limits	Three-year variability limits
	2014 and thereafter (tons)	2016 and thereafter (tons)
Georgia	8,572	4,949
Illinois	15,153	8,749
Indiana	20,141	11,629
Iowa	8,609	4,970
Kentucky	11,384	6,573
Michigan	15,568	8,988
Missouri	15,876	9,166
New York	4,204	2,427
North Carolina	8,186	4,726
Ohio	17,831	10,295
Pennsylvania	14,169	8,181
Tennessee	10,001	5,774
Virginia	4,079	2,355
West Virginia	11,902	6,871
Wisconsin	6,668	3,850

§ 97.611 Timing requirements for TR SO_2 Group 1 allowance allocations.

(a) *Existing units.* (1) TR SO_2 Group 1 allowances are allocated, for the control periods in 2012 and each year thereafter, as set forth in appendix A to this subpart. Listing a unit in such appendix does not constitute a determination that the unit is a TR SO_2 Group 1 unit, and not listing a unit in such appendix does not constitute a determination that the unit is not a TR SO_2 Group 1 unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit listed in appendix A to this subpart as being allocated TR SO_2 Group 1 allowances does not operate, starting after 2011, during the control period in three consecutive years, such unit will not be allocated the TR SO_2 Group 1 allowances set forth in appendix A to this subpart for the unit for the control periods in the seventh year after the first such year and in each year after that seventh year. All TR SO_2 Group 1 allowances that would otherwise have been allocated to such unit will be allocated to the new unit set-aside for the respective years involved. If such unit resumes operation, the Administrator will allocate TR SO_2 Group 1 allowances to the unit in accordance with paragraph (b) of this section.

(b) *New units.* (1) By July 1, 2012 and July 1 of each year thereafter, the Administrator will calculate the TR SO_2 Group 1 allowance allocation for each TR SO_2 Group 1 unit, in accordance with § 97.612, for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of availability of the results of the calculations.

(2) For each notice of data availability required in paragraph (b)(1) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations are in accordance with § 97.612 and §§ 97.606(b)(2) and 97.630 through 97.635.

(ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By September 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.

(c) *Units that are not TR SO_2 Group 1 units.* For each control period in 2012 and thereafter, if the Administrator determines that TR SO_2 Group 1 allowances were allocated under paragraph (a) of this section for the control period to a recipient that is not actually a TR SO_2 Group 1 unit under § 97.604 as of January 1, 2012 or whose deadline for meeting monitor certification requirements under § 97.630(b)(1) and (2) is after January 1, 2012 or if the Administrator determines that TR SO_2 Group 1 allowances were allocated under paragraph (b) of this section and § 97.612 for the control period to a recipient that is not actually a TR SO_2 Group 1 unit under § 97.604 as of January 1 of the control period, then the Administrator will notify the designated representative and will act in accordance with the following procedures:

(1) Except as provided in paragraph (c)(2) or (3) of this section, the Administrator will not record such TR SO_2 Group 1 allowances under § 97.621.

(2) If the Administrator already recorded such TR SO_2 Group 1 allowances under § 97.621 and if the Administrator makes such determination before making deductions for the source that includes such recipient under § 97.624(b) for such control period, then the Administrator will deduct from the account in which such TR SO_2 Group 1 allowances were recorded an amount of TR SO_2 Group 1 allowances allocated for the same or a prior control period equal to the amount of such already recorded TR SO_2 Group 1 allowances. The authorized account representative shall ensure that there are sufficient TR SO_2 Group 1 allowances in such account for completion of the deduction.

(3) If the Administrator already recorded such TR SO_2 Group 1 allowances under § 97.621 and if the Administrator makes such determination after making deductions for the source that includes such recipient under § 97.624(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded TR SO_2 Group 1 allowances.

(4) The Administrator will transfer the TR SO_2 Group 1 allowances that are not recorded, or that are deducted, in accordance with paragraphs (c)(1) and (2) of this section to the new unit set-aside, for the State in which such recipient is located, for the control period in the year of such transfer if the notice required in paragraph (b)(1) of this section for the control period in that year has not been promulgated or, if such notice has been promulgated, in the next year.

§ 97.612 TR SO_2 Group 1 allowance allocations for new units.

(a) For each control period in 2012 and thereafter, the Administrator will allocate, in accordance with the following procedures, TR SO_2 Group 1 allowances to TR SO_2 Group 1 units in a State that are not listed in appendix A to this subpart, to TR SO_2 Group 1 units that are so listed and whose allocation of SO_2 Group 1 allowances for such control period is covered by § 97.611(c)(1) or (2), and to TR SO_2 Group 1 units that are so listed and, pursuant to § 97.611(a)(2), are not allocated TR SO_2 Group 1 allowances for such control period but that operate during the immediately preceding control period:

(1) The Administrator will establish a separate new unit set-aside for each State for each control period in a given year. Each new unit set-aside will be allocated TR SO_2 Group 1 allowances in an amount equal to the applicable amount of tons of SO_2 emissions as set forth in § 97.610(a). Each new unit set-aside will be allocated additional TR SO_2 Group 1 allowances in accordance with § 97.611(a)(2) and (c)(4).

(2) The designated representative of such TR SO_2 Group 1 unit may submit to the Administrator a request, in a format prescribed by the Administrator, to be allocated TR SO_2 Group 1 allowances for a control period, starting with the later of the control period in 2012, the first control period after the control period in which the TR SO_2 Group 1 unit commences commercial operation (for a unit not listed in appendix A to this subpart), or the first control period after the control period in which the unit resumes operation (for a unit listed in appendix A of this subpart) and for each subsequent control period.

(i) The request must be submitted on or before May 1 of the first control period for which TR SO_2 Group 1 allowances are sought and after the date on which the TR SO_2 Group 1 unit commences commercial operation (for a unit not listed in appendix A of this subpart) or on which the unit resumes operation (for a unit listed in appendix A of this subpart).

(ii) For each control period for which an allocation is sought, the request must be for TR SO_2 Group 1 allowances in an amount equal to the unit's total tons of SO_2 emissions during the immediately preceding control period.

(3) The Administrator will review each TR SO_2 Group 1 allowance allocation request under paragraph (a)(2) of this section and will accept the request only if it meets the requirements of paragraph (a)(2) of this section. The Administrator will allocate TR SO_2 Group 1 allowances for each control period pursuant to an accepted request as follows:

(i) After May 1 of such control period, the Administrator will determine the sum of the TR SO_2 Group 1 allowances requested in all accepted allowance allocation requests for such control period.

(ii) If the amount of TR SO_2 Group 1 allowances in the new unit set-aside for such control period is greater than or equal to the sum under paragraph (a)(3)(i) of this section, then the Administrator will allocate the amount of TR SO_2 Group 1 allowances requested to each TR SO_2 Group 1 unit covered by an accepted allowance allocation request.

(iii) If the amount of TR SO_2 Group 1 allowances in the new unit set-aside for such control period is less than the sum under paragraph (a)(3)(i) of this section, then the Administrator will allocate to each TR SO_2 Group 1 unit covered by an accepted allowance allocation request the amount of the TR SO_2 Group 1 allowances requested, multiplied by the amount of TR SO_2 Group 1 allowances in the new unit set-aside for such control period, divided by the sum determined under paragraph (a)(3)(i) of this section, and rounded to the nearest allowance.

(iv) The Administrator will notify, through the promulgation of the notices of data availability described in § 97.611(b), each designated representative that submitted an allowance allocation request of the amount of TR SO_2 Group 1 allowances (if any) allocated for such control period to the TR SO_2 Group 1 unit covered by the request.

(b) If, after completion of the procedures under paragraph (a)(4) of this section for a control period, any unallocated TR SO_2 Group 1 allowances remain in the new unit set-aside under paragraph (a) of this section for a State for such control period, the Administrator will allocate to each TR SO_2 Group 1 unit that is in the State, is listed in appendix A to this subpart, and continues to be allocated TR SO_2 Group 1 allowances for such control period in accordance with § 97.611(a)(2), an amount of TR SO_2 Group 1 allowances equal to the following: The total amount of such remaining unallocated TR SO_2 Group 1 allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.611(a) for such control period, divided by the remainder of the amount of tons in the applicable State SO_2 Group 1 trading budget minus the amount of tons in such new unit set-aside, and rounded to the nearest allowance.

§ 97.613 Authorization of designated representative and alternate designated representative.

(a) Except as provided under § 97.615, each TR SO_2 Group 1 source, including all TR SO_2 Group 1 units at the source, shall have one and only one designated representative, with regard to all matters under the TR SO_2 Group 1 Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR SO_2 Group 1 units at the source and shall act in accordance with the certification statement in § 97.616(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.616:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each TR SO_2 Group 1 unit at the source in all matters pertaining to the TR SO_2 Group 1 Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under § 97.615, each TR SO_2 Group 1 source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR SO_2 Group 1 units at the source and shall act in accordance with the certification statement in § 97.616(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.616,

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit. (c) Except in this section, § 97.602, and §§ 97.614 through 97.618, whenever the term "designated representative" is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 97.614 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under § 97.618 concerning delegation of authority to make submissions, each submission under the TR SO_2 Group 1 Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each TR SO_2 Group 1 source and TR SO_2 Group 1 unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or 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."

(b) The Administrator will accept or act on a submission made for a TR SO_2 Group 1 source or a TR SO_2 Group 1 unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 97.618.

§ 97.615 Changing designated representative and alternate designated representative; changes in owners and operators.

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.616. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the TR SO_2 Group 1 source and the TR SO_2 Group 1 units at the source.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.616. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the TR SO_2 Group 1 source and the TR SO_2 Group 1 units at the source.

(c) *Changes in owners and operators.* (1) In the event an owner or operator of a TR SO_2 Group 1 source or a TR SO_2 Group 1 unit is not included in the list of owners and operators in the certificate of representation under § 97.616, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a TR SO_2 Group 1 source or a TR SO_2 Group 1 unit, including the addition of a new owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under § 97.616 amending the list of owners and operators to include the change.

§ 97.616 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the TR SO_2 Group 1 source, and each TR SO_2 Group 1 unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe rounded to the nearest tenth) of each generator served by each such unit, and actual or projected date of commencement of commercial operation.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the TR SO_2 Group 1 source and of each TR SO_2 Group 1 unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) "I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each TR SO_2 Group 1 unit at the source."

(ii) "I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR SO_2 Group 1 Trading Program on behalf of the owners and operators of the source and of each TR SO_2 Group 1 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 order issued to me by the Administrator regarding the source or unit."

(iii) "Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a TR SO_2 Group 1 unit, or where a utility or industrial customer purchases power from a TR SO_2 Group 1 unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each TR SO_2 Group 1 unit at the source; and TR SO_2 Group 1 allowances and proceeds of transactions involving TR SO_2 Group 1 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of TR SO_2 Group 1 allowances by contract, TR SO_2 Group 1 allowances and proceeds of transactions involving TR SO_2 Group 1 allowances will be deemed to be held or distributed in accordance with the contract."

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.617 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under § 97.616 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 97.616 is received by the Administrator.

(b) Except as provided in § 97.615(a) or (b), no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the TR SO_2 Group 1 Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of TR SO_2 Group 1 allowance transfers.

§ 97.618 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.618(d) shall be deemed to be an electronic submission by me."

(ii) "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.618(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.618 is terminated.".

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

§ 97.619 [Reserved]

§ 97.620 Establishment of Allowance Management System accounts.

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under § 97.616, the Administrator will establish a compliance account for the TR SO_2 Group 1 source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *General accounts*—(1) *Application for general account.* (i) Any person may apply to open a general account, for the purpose of holding and transferring TR SO_2 Group 1 allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the TR SO_2 Group 1 allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR SO_2 Group 1 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 regarding the general account."

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of authorized account representative and alternate authorized account representative.* (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account in all matters pertaining to the TR SO_2 Group 1 Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account shall be bound by any order or decision issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account. (ii) Except as provided in paragraph (b)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the TR SO_2 Group 1 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."

(iii) Except in this section, whenever the term "authorized account representative" is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) *Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.* (i) The authorized account representative of 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 authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the TR SO_2 Group 1 allowances in the general account.

(ii) The alternate authorized account representative of 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 authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the TR SO_2 Group 1 allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to TR SO_2 Group 1 allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to SO_2 Group 1 allowances in the general account, including the addition of a new person, the authorized account representative or any alternate 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 TR SO_2 Group 1 allowances in the general account to include the change.

(4) *Objections concerning authorized account representative and alternate authorized account representative.* (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)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the TR SO_2 Group 1 Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of TR SO_2 Group 1 allowance transfers.

(5) *Delegation by authorized account representative and alternate authorized account representative.* (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (b)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (b)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.620(b)(5)(iv) shall be deemed to be an electronic submission by me."; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.620(b)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.620(b)(5) is terminated.".

(iv) A notice of delegation submitted under paragraph (b)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (b)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (b)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6)(i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted TR SO_2 Group 1 allowance transfer under § 97.622 for any TR SO_2 Group 1 allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no TR SO_2 Group 1 allowance transfers to or from the account for a 12-month period or longer and does not contain any TR SO_2 Group 1 allowances, the Administrator may notify the authorized account representative for the account that the account will be closed after 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 TR SO_2 Group 1 allowance transfer under § 97.622 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

(d) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of an Allowance Management System account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of TR SO_2 Group 1 allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 97.614(a) and 97.618 or paragraphs (b)(2)(ii) and (b)(5) of this section.

§ 97.621 Recordation of TR SO_2 Group 1 allowance allocations.

(a) By September 1, 2011, the Administrator will record in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated for the TR SO_2 Group 1 units at the source in accordance with §§ 97.611(a) for the control periods in 2012, 2013, and 2014.

(b) By June 1, 2012 and June 1 of each year thereafter, the Administrator will record in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated for the TR SO_2 Group 1 units at the source in accordance with § 97.611(a) for the control period in the third year after the year of the applicable recordation deadline under this paragraph.

(c) By September 1, 2012 and September 1 of each year thereafter, the Administrator will record in each TR SO_2 Group 1 source's compliance account the TR SO_2 Group 1 allowances allocated for the TR SO_2 Group 1 units at the source in accordance with § 97.612 for the control period in the year of the applicable recordation deadline under this paragraph.

(d) When recording the allocation of TR SO_2 Group 1 allowances for a TR

SO_2 Group 1 unit in a compliance account, the Administrator will assign each TR SO_2 Group 1 allowance a unique identification number that will include digits identifying the year of the control period for which the TR SO_2 Group 1 allowance is allocated.

§ 97.622 Submission of TR SO_2 Group 1 allowance transfers.

(a) An authorized account representative seeking recordation of a TR SO_2 Group 1 allowance transfer shall submit the transfer to the Administrator.

(b) A TR SO_2 Group 1 allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each TR SO_2 Group 1 allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each TR SO_2 Group 1 allowance identified by serial number in the transfer.

§ 97.623 Recordation of TR SO_2 Group 1 allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a TR SO_2 Group 1 allowance transfer, the Administrator will record a TR SO_2 Group 1 allowance transfer by moving each TR SO_2 Group 1 allowance from the transferor account to the transferee account as specified by the request, provided that the transfer is correctly submitted under § 97.622.

(b)(1) A TR SO_2 Group 1 allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any TR SO_2 Group 1 allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 97.624 for the control period immediately before such allowance transfer deadline.

(2) A TR SO_2 Group 1 allowance transfer that is submitted for recordation after the deadline for holding TR SO_2 Group 1 allowances described in § 97.625(b)(5) and that includes any TR SO_2 Group 1 allowances allocated for a control period before the year of such deadline will not be recorded until after the Administrator completes the deductions under § 97.625 for the control period immediately before the year of such deadline.

(c) Where a TR SO_2 Group 1 allowance transfer is not correctly submitted under § 97.622, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a TR SO_2 Group 1 allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a TR SO_2 Group 1 allowance transfer that is not correctly submitted under § 97.622, the Administrator will notify the 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.

§ 97.624 Compliance with TR SO_2 Group 1 emissions limitation.

(a) *Availability for deduction for compliance.* TR SO_2 Group 1 allowances are available to be deducted for compliance with a source's TR SO_2 Group 1 emissions limitation for a control period in a given year only if the TR SO_2 Group 1 allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in the source's compliance account as of the allowance transfer deadline for such control period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 97.623, of TR SO_2 Group 1 allowance transfers submitted by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account TR SO_2 Group 1 allowances available under paragraph (a) of this section in order to determine whether the source meets the TR SO_2 Group 1 emissions limitation for such control period, as follows:

(1) Until the amount of TR SO_2 Group 1 allowances deducted equals the number of tons of total SO_2 emissions from all TR SO_2 Group 1 units at the source for such control period; or

(2) If there are insufficient TR SO_2 Group 1 allowances to complete the deductions in paragraph (b)(1) of this section, until no more TR SO_2 Group 1 allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of TR SO_2 Group 1 allowances by serial number.* The authorized account representative for a source's compliance account may request that specific TR SO_2 Group 1 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the TR SO_2 Group 1 source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR SO_2 Group 1 allowances under paragraph (b) or (d) of this section from the source's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR SO_2 Group 1 allowances in such request, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any TR SO_2 Group 1 allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR SO_2 Group 1 allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Deductions for excess emissions.* After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the TR SO_2 Group 1 source has excess emissions, the Administrator will deduct from the source's compliance account an amount of TR SO_2 Group 1 allowances, allocated for the control period in the immediately following year, equal to two times the number of tons of the source's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.625 Compliance with TR SO_2 Group 1 assurance provisions.

(a) *Availability for deduction.* TR SO_2 Group 1 allowances are available to be deducted for compliance with the TR SO_2 Group 1 assurance provisions for a control period in a given year by an owner of one or more TR SO_2 Group 1 units in a State only if the TR SO_2 Group 1 allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in a compliance account, designated by the owner in accordance

with paragraph (b)(4)(ii) of this section, of one of the owner's TR SO_2 Group 1 sources in the State as of the deadline established in paragraph (b)(5) of this section.

(b) *Deductions for compliance.* The Administrator will deduct TR SO_2 Group 1 allowances available under paragraph (a) of this section for compliance with the TR SO_2 Group 1 assurance provisions for a State for a control period in a given year in accordance with the following procedures:

(1) By June 1, 2015 and June 1 of each year thereafter, the Administrator will:

(i) Calculate, separately for each State, the total amount of SO_2 emissions from all TR SO_2 Group 1 units in the State during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total amount of NO_X emissions exceeds the State assurance level as described in § 97.606(c)(2)(iii); and

(ii) Promulgate a notice of availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the SO_2 emissions for each TR SO_2 Group 1 unit and of the amounts described in §§ 97.606(c)(2)(iii)(A) and (B) for each State.

(2) The Administrator will provide an opportunity for submission of objections to the calculations referenced by each notice described in paragraph (b)(1) of this section.

(i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations for each TR SO_2 Group 1 unit and each State for the control period in the year involved are in accordance with § 97.606(c)(2)(iii) and §§ 97.606(b) and 97.630 through 97.635.

(ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By August 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.

(3) For each notice of data availability required in paragraph (b)(2)(ii) of this section and for any State identified in such notice as having TR SO_2 Group 1 sources with total SO_2 emissions exceeding the State assurance level for a control period, as described in § 97.606(c)(2)(iii):

(i) By August 15 immediately after the promulgation of such notice, the designated representative of each TR SO_2 Group 1 source in each such State shall submit a statement, in a format prescribed by the Administrator:

(A) Listing all the owners of each TR SO_2 Group 1 unit at the source, explaining how the selection of each owner for inclusion on the list is consistent with the definition of "owner" in § 97.602, and listing, separately for each unit, the percentage of the legal, equitable, leasehold, or contractual reservation or entitlement for each such owner as of midnight of December 31 of the control period in the year involved; and

(B) For each TR SO_2 Group 1 unit at the source that operates during, but is allocated no TR SO_2 Group 1 allowances for, the control period in the year involved, identifying whether the unit is a coal-fired boiler, simple combustion turbine, or combined cycle turbine cycle and providing the unit's allowable SO_2 emission rate for such control period.

(ii) By September 15 immediately after the promulgation of such notice, the Administrator will calculate, for each such State and each owner of one or more TR SO_2 Group 1 units in the State and for the control period in the year involved, each owner's share of the total SO_2 emissions from all TR SO_2 Group 1 units in the State, each owner's assurance level, and the amount (if any) of TR SO_2 Group 1 allowances that each owner must hold in accordance with the calculation formula in § 97.606(c)(2)(i) and will promulgate a notice of availability of the results of these calculations.

(iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(3)(ii) of this section.

(A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations for each owner for the control period in the year involved are consistent with the SO_2 emissions for the relevant TR SO_2 Group 1 units as set forth in the notice required in paragraph (b)(2)(ii) of this section, the definitions of "owner", "owner's assurance level", and "owner's share" in § 97.602, and the calculation formula in § 97.606(c)(2)(i) and shall not raise any issues about any data used in the notice of data availability required in paragraph (b)(2)(ii) of this section.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are consistent with the data and provisions referenced in paragraph (b)(3)(iii)(A) of this section. By November 15 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(3)(iii)(A) of this section.

(4) By December 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section:

(i) Each owner identified, in such notice, as owning one or more TR SO_2 Group 1 units in a State and as being required to hold TR SO_2 Group 1 allowances shall designate the compliance account of one of the sources at which such unit or units are located to hold such required TR SO_2 Group 1 allowances;

(ii) The authorized account representative for the compliance account designated under paragraph (b)(4)(i) of this section shall submit to the Administrator a statement, in a format prescribed by the Administrator, making this designation.

(5)(i) As of midnight of December 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section, each owner described in paragraph (b)(4)(i) of this section shall hold in the compliance account designated by the owner in accordance with paragraph (b)(4)(ii) of this section the total amount of TR SO_2 Group 1 allowances, available for deduction under paragraph (a) of this section, equal to the amount the owner is required to hold as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(5)(i) of this section, if December 15 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(6) After December 15 (or the date described in paragraph (b)(5)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section and after the recordation, in accordance with § 97.623, of TR SO_2 Group 1 allowance transfers submitted by midnight of such date, the Administrator will deduct from each compliance account designated in accordance with paragraph (b)(4)(ii) of this section, TR SO_2 Group 1 allowances available under paragraph (a) of this section, as follows:

(i) Until the amount of TR SO_2 Group 1 allowances deducted equals the amount that the owner designating the compliance account is required to hold as calculated by the Administrator and referenced in the notice required in paragraph (b)(3)(iii)(B) of this section; or

(ii) If there are insufficient TR SO_2 Group 1 allowances to complete the deductions in paragraph (b)(6)(i) of this section, until no more TR SO_2 Group 1 allowances available under paragraph (a) of this section remain in the compliance account.

(7) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notices of data availability required in paragraphs (b)(2)(ii) and (b)(3)(iii)(B) of this section respectively for a control period, of any data used in making the calculations referenced in such notice, the amount of TR SO_2 Group 1 allowances that each owner is required to hold in accordance with § 97.606(c)(2)(i) for the control period in the year involved shall continue to be such amount as calculated by the Administrator and referenced in such notice required in paragraph (b)(3)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of TR SO_2 Group 1 allowances that owners are required to hold in accordance with the calculation formula in § 97.606(c)(2)(i) for the control period in the year involved with regard to the State involved, provided that—

(A) With regard to such litigation involving such notice required in paragraph (b)(2)(ii) of this section, such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(ii) of this section; and

(B) With regard to such litigation involving such notice required in paragraph (b)(3)(iii) of this section, such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(3)(iii) of this section.

(ii) If any such data are revised by the owners and operators of a source whose designated representative submitted such data under paragraph (b)(3)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of TR SO_2 Group 1 allowances that owners are required to hold in accordance with the calculation formula in § 97.606(c)(2)(i) for the control period in the year involved with regard to the State involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(3)(iii)(B) of this section.

(iii) If the revised data are used to recalculate, in accordance with paragraphs (b)(7)(i) and (b)(7)(ii) of this section, the amount of TR SO_2 Group 1 allowances that an owner is required to hold for the control period in the year involved with regard to the State involved—

(A) Where the amount of TR SO_2 Group 1 allowances that an owner is required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owner shall hold the additional amount of TR SO_2 Group 1 allowances in the compliance account designated by the owner in accordance with paragraph (b)(4)(ii) of this section. The owner's failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owner's failure to hold such additional amount, as required, as of the new deadline shall be a violation of the Clean Air Act. Each TR SO_2 Group 1 allowance that the owner fails to hold as required as of the new deadline, and each day in the control period in the year involved, shall be a separate violation of the Clean Air Act. After such deadline, the Administrator will make the appropriate deductions from the compliance account.

(B) For an owner for which the amount of TR SO_2 Group 1 allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in the compliance account that the owner designated in accordance with paragraph (b)(4)(ii) of this section, an amount of TR SO_2 Group 1 allowances equal to the amount of the decrease to the extent such amount was previously deducted from the compliance account under paragraph (b)(6) of this section (and has not already been restored to the compliance account) for the control period in the year involved.

(C) Each TR SO_2 Group 1 allowance held and deducted under paragraph (b)(7)(iii)(A) of this section, or recorded under paragraph (b)(7)(iii)(B) of this section, as a result of recalculation of requirements under the TR SO_2 Group 1 assurance provisions for a control period in a given year must be a TR SO_2 Group 1 allowance allocated for a control period in the same or a prior year.

(c)(1) *Identification of TR SO_2 Group 1 allowances by serial number.* The authorized account representative for each source's compliance account designated in accordance with paragraph (b)(4)(ii) of this section may request that specific TR SO_2 Group 1 allowances, identified by serial number, in the compliance account be deducted in accordance with paragraph (b)(6) or (7) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance-holding deadline described in paragraph (b)(5) of this section and include, in a format prescribed by the Administrator, the identification of the compliance account and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR SO_2 Group 1 allowances under paragraphs (b)(6) and (7) of this section from each source's compliance account designated under paragraph (b)(4)(ii) of this section in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR SO_2 Group 1 allowances in such request, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any TR SO_2 Group 1 allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR SO_2 Group 1 allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraph (b) of this section.

§ 97.626 Banking.

(a) A TR SO_2 Group 1 allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any TR SO_2 Group 1 allowance that is held in a compliance account or a general account will remain in such account unless and until the TR SO_2 Group 1 allowance is deducted or transferred under § 97.611(c), § 97.623, § 97.624, § 97.625, 97.627, 97.628, 97.642, or 97.643.

§ 97.627 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.628 Administrator's action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the TR SO_2 Group 1 Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct TR SO_2 Group 1 allowances from or transfer TR SO_2 Group 1 allowances to a source's compliance account based on the information in a submission, as adjusted under paragraph (a)(1) of this section, and record such deductions and transfers.

§ 97.629 [Reserved]

§ 97.630 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a TR SO_2 Group 1 unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subparts F and G of part 75 of this chapter. For purposes of applying such requirements, the definitions in § 97.602 and in § 72.2 of this chapter shall apply, the terms "affected unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") in part 75 of this chapter shall be deemed to refer to the terms "TR SO_2 Group 1 unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") respectively as defined in § 97.602, and the term "newly affected unit" shall be deemed to mean "newly affected TR SO_2 Group 1 unit." The owner or operator of a unit that is not a TR SO_2 Group 1 unit but that is monitored under § 75.16(b)(2) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a TR SO_2 Group 1 unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each TR SO_2 Group 1 unit shall:

(1) Install all monitoring systems required under this subpart for monitoring SO_2 mass emissions and individual unit heat input (including all systems required to monitor SO_2 concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.11 and 75.16 of this chapter);

(2) Successfully complete all certification tests required under § 97.631 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a TR SO_2 Group 1 unit that commences commercial operation before July 1, 2011, by January 1, 2012.

(2) For the owner or operator of a TR SO_2 Group 1 unit that commences commercial operation on or after July 1, 2011, by the later of the following dates:

(i) January 1, 2012; or

(ii) 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation.

(3) For the owner or operator of a TR SO_2 Group 1 unit for which construction of a new stack or flue or installation of add-on SO_2 emission controls is completed after the applicable deadline under paragraph (b)(1) or (2) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on SO_2 emissions controls.

(4) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved, by the date specified in § 97.641(c).

(5) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a TR SO_2 Group 1 opt-in unit, by the date on which the TR SO_2 Group 1 opt-in unit enters the TR SO_2 Group 1 Trading Program as provided in § 97.641(h).

(c) *Reporting data.* The owner or operator of a TR SO_2 Group 1 unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for SO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine SO_2 mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter or section 2.4 of appendix D to part 75 of this chapter, as applicable.

(d) *Prohibitions.* (1) No owner or operator of a TR SO_2 Group 1 unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 97.635.

(2) No owner or operator of a TR SO_2 Group 1 unit shall operate the unit so as to discharge, or allow to be discharged, SO_2 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.

(3) No owner or operator of a TR SO_2 Group 1 unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO_2 mass emissions discharged into the atmosphere or heat input, 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.

(4) No owner or operator of a TR SO_2 Group 1 unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 97.605 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 Administrator 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 designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 97.631(d)(3)(i).

(e) *Long-term cold storage.* The owner or operator of a TR SO_2 Group 1 unit is subject to the applicable provisions of § 75.4(d) of this chapter concerning units in long-term cold storage.

§ 97.631 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a TR SO_2 Group 1 unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 97.630(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendices B and D to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 97.630(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) [Reserved]

(d) Except as provided in paragraph (a) of this section, the owner or operator of a TR SO_2 Group 1 unit shall comply with the following initial certification and recertification procedures, for a continuous monitoring system (*i.e.,* a continuous emission monitoring system and an excepted monitoring system under appendix D to part 75 of this chapter) under § 97.630(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under § 97.630(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 97.630(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 97.630(a)(1) that may significantly affect the ability of the system to accurately measure or record SO_2 mass emissions or heat input rate or to meet the quality-assurance and quality-control 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 in accordance with § 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 may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: Replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system under § 97.630(a)(1) is subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* For initial certification of a continuous monitoring system under § 97.630(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words "certification" and "initial certification" are replaced by the word "recertification" and the word "certified" is replaced by with the word "recertified".

(i) *Notification of certification.* The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with § 97.633.

(ii) *Certification application.* The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the TR SO_2 Group 1 Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, 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 Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) *Certification application approval process.* The Administrator 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 (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that 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 TR SO_2 Group 1 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 Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period specified in paragraph (d)(3) of this section shall not begin before receipt of a complete certification application.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator 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 Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter).

(D) *Audit decertification.* The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 97.632(b).

(v) *Procedures for loss of certification.* If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(*1*) For a disapproved SO_2 pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of SO_2 and the maximum potential flow rate, as defined in sections 2.1.1.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(*2*) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(*3*) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 97.632 Monitoring system out-of-control periods.

(a) *General provisions.* Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or appendix D to 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 monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 97.631 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 Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system 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 for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 97.631 for each disapproved monitoring system.

§ 97.633 Notifications concerning monitoring.

The designated representative of a TR SO_2 Group 1 unit shall submit written notice to the Administrator in accordance with § 75.61 of this chapter.

§ 97.634 Recordkeeping and reporting.

(a) *General provisions.* The designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements in subparts F and G of part 75 of this chapter, and the requirements of § 97.614(a).

(b) *Monitoring plans.* The owner or operator of a TR SO_2 Group 1 unit shall comply with requirements of § 75.62 of this chapter.

(c) *Certification applications.* The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under § 97.631, including the information required under § 75.63 of this chapter.

(d) *Quarterly reports.* The designated representative shall submit quarterly reports, as follows:

(1) The designated representative shall report the SO_2 mass emissions data and heat input data for the TR SO_2 Group 1 unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering January 1, 2012 through March 31, 2012;

(ii) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.630(b), unless that quarter is the third or fourth quarter of 2011, in which case reporting shall commence in the quarter covering January 1, 2012 through March 31, 2012;

(iii) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved, the calendar quarter corresponding to the date specified in § 97.641(c); and

(iv) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a TR SO_2 Group 1 opt-in unit, the calendar quarter corresponding to the date on which the TR SO_2 Group 1 opt-in unit enters the TR SO_2 Group 1 Trading Program as provided in § 97.641(h).

(2) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.64 of this chapter.

(3) For TR SO_2 Group 1 units that are also subject to the Acid Rain Program, TR NO_X Annual Trading Program, or TR NO_X Ozone Season Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the SO_2 mass emission data, heat input data, and other information required by this subpart.

(4) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(ii) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(2) of this section.

(e) *Compliance certification.* The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) 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:

(1) 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

(2) For a unit with add-on SO_2 emission controls and for all hours where SO_2 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 quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate SO_2 emissions.

§ 97.635 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a TR SO_2 Group 1 unit may submit a petition under § 75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§ 97.630 through 97.634 or paragraph (5)(i) or (ii) of the definition of "owner's share" in § 97.602.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(i) Identification of each unit and source covered by the petition;

(ii) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(iii) A description and diagram of any equipment and procedures used in the proposed alternative;

(iv) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be *de minimis;* and

(v) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

§ 97.640 General requirements for TR SO_2 Group 1 opt-in units.

(a) A TR SO_2 Group 1 opt-in unit must be a unit that:

(1) Is located in a State;

(2) Is not a TR SO_2 Group 1 unit under § 97.604;

(3) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect; and

(4) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of this subpart.

(b) A TR SO_2 Group 1 opt-in unit shall be deemed to be a TR SO_2 Group 1 unit for purposes of applying this subpart, except for §§ 97.605, 97.611, and 97.612.

(c) Solely for purposes of applying the requirements of §§ 97.613 through 97.618 and §§ 97.630 through 97.635, a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved under § 97.642 shall be deemed to be a TR SO_2 Group 1 unit.

(d) Any TR SO_2 Group 1 opt-in unit, and any unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved under § 97.642, located at the same source as one or more TR SO_2 Group 1 units shall have the same designated representative and alternate designated representative as such TR SO_2 Group 1 units.

§ 97.641 Opt-in process.

A unit meeting the requirements for a TR SO_2 Group 1 opt-in unit in § 97.640(a) may become a TR SO_2 Group 1 opt-in unit only if, in accordance with this section, the designated representative of the unit submits a complete TR opt-in application for the unit and the Administrator approves the application.

(a) *Applying to opt-in.* The designated representative of the unit may submit a complete TR opt-in application for the unit at any time, except as provided under § 97.642(e). A complete TR opt-in application shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the unit and the source where the unit is located,

including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, and unit identification number and type;

(2) A certification that the unit:

(i) Is not a TR SO_2 Group 1 unit under § 97.604;

(ii) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(iii) Vents all of its emissions to a stack; and

(iv) Has documented heat input (greater than 0 mmBtu) for more than 876 hours during the 6 months immediately preceding submission of the TR opt-in application;

(3) A monitoring plan in accordance with §§ 97.630 through 97.635;

(4) A statement that the unit, if approved to become a TR SO_2 Group 1 unit under paragraph (g) of this section, may withdraw from the TR SO_2 Group 1 Trading Program only in accordance with § 97.642;

(5) A statement that the unit, if approved to become a TR SO_2 Group 1 unit under paragraph (g) of this section, is subject to, and the owners and operators of the unit must comply with, the requirements of § 97.643;

(6) A complete certificate of representation under § 97.616 consistent with § 97.640, if no designated representative has been previously designated for the source that includes the unit; and

(7) The signature of the designated representative and the date signed.

(b) *Interim review of monitoring plan.* The Administrator will determine, on an interim basis, the sufficiency of the monitoring plan submitted under paragraph (a)(3) of this section. The monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the SO_2 emission rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with §§ 97.630 through 97.635. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(c) *Monitoring and reporting.* (1)(i) If the Administrator determines that the monitoring plan is sufficient under paragraph (b) of this section, the owner or operator of the unit shall monitor and report the SO_2 emission rate and the heat input of the unit and all other applicable parameters, in accordance with §§ 97.630 through 97.635, starting on the date of certification of the necessary monitoring systems under §§ 97.630 through 97.635 and continuing until the TR opt-in application submitted under paragraph (a) of this section is disapproved under this section or, if such TR opt-in application is approved, the date and time when the unit is withdrawn from the TR SO_2 Group 1 Trading Program in accordance with § 97.642.

(ii) The monitoring and reporting under paragraph (c)(1)(i) of this section shall cover the entire control period immediately before the date on which the unit enters the TR SO_2 Group 1 Trading Program under paragraph (h) of this section, during which period monitoring system availability must not be less than 98 percent under §§ 97.630 through 97.635 and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the SO_2 emission rate and the heat input of the unit are monitored and reported in accordance with §§ 97.630 through 97.635 for one or more entire control periods, in addition to the control period under paragraph (c)(1)(ii) of this section, during which control periods monitoring system availability is not less than 98 percent under §§ 97.630 through 97.635 and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the TR SO_2 Group 1 Trading Program under paragraph (h) of this section, such information shall be used as provided in paragraphs (e) and (f) of this section.

(d) *Statement on compliance.* After submitting to the Administrator all quarterly reports required for the unit under paragraph (c) of this section, the designated representative shall submit, in a format prescribed by the Administrator, to the Administrator a statement that, for the years covered by such quarterly reports, the unit was in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(e) *Baseline heat input.* The unit's baseline heat input shall equal:

(1) If the unit's SO_2 emission rate and heat input are monitored and reported for only one entire control period, in accordance with paragraph (c) of this section, the unit's total heat input (in mmBtu) for such control period; or

(2) If the unit's SO_2 emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, the average of the amounts of the unit's total heat input (in mmBtu) for such control periods.

(f) *Baseline SO_2 emission rate.* The unit's baseline SO_2 emission rate shall equal:

(1) If the unit's SO_2 emission rate and heat input are monitored and reported for only one entire control period, in accordance with paragraph (c) of this section, the unit's SO_2 emission rate (in lb/mmBtu) for such control period;

(2) If the unit's SO_2 emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, and the unit does not have add-on SO_2 emission controls during any such control periods, the average of the amounts of the unit's SO_2 emission rate (in lb/mmBtu) for such control periods; or

(3) If the unit's SO_2 emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, and the unit has add-on SO_2 emission controls during any such control periods, the average of the amounts of the unit's SO_2 emission rate (in lb/mmBtu) for such control periods during which the unit has add-on SO_2 emission controls.

(g) *Review of TR opt-in application.* (1) After the designated representative submits the complete TR opt-in application, quarterly reports, and statement required in paragraphs (a), (c), and (d) of this section and if the Administrator determines that the designated representative shows that the unit meets the requirements for a TR SO_2 Group 1 opt-in unit in § 97.640, the element certified in paragraph (a)(2)(iv) of this section, and the monitoring and reporting requirements of paragraph (c) of this section, the Administrator will issue a written approval of the TR opt-in application for the unit. The written approve will state the unit's baseline heat input and baseline SO_2 emission rate. The Administrator will thereafter establish a compliance account for the source that includes the unit unless the source already has a compliance account.

(2) Notwithstanding paragraphs (a) through (f) of this section, if, at any time before the TR opt-in application is approved under paragraph (g)(1) of this section, the Administrator determines that the unit cannot meet the requirements for a TR SO_2 Group 1 opt-in unit in § 97.640, the element certified in paragraph (a)(2)(iv) of this section, or the monitoring and reporting requirements in paragraph (c) of this section, the Administrator will issue a written disapproval of the TR opt-in application for the unit.

(h) *Date of entry into TR SO_2 Group 1 Trading Program.* A unit for which a

TR opt-in application is approved under paragraph (g)(1) of this section shall become a TR SO_2 Group 1 opt-in unit, and a TR SO_2 Group 1 unit, effective as of the later of January 1, 2012, or January 1 of the first control period during which such approval is issued.

§ 97.642 Withdrawal of TR SO_2 Group 1 opt-in unit from TR SO_2 Group 1 Trading Program.

A TR SO_2 Group 1 opt-in unit may withdraw from the TR SO_2 Group 1 Trading Program only if, in accordance with this section, the designated representative of the unit submits a request to withdraw the unit and the Administrator issues a written approval of the request.

(a) *Requesting withdrawal.* In order to withdraw the TR SO_2 Group 1 opt-in unit from the TR SO_2 Group 1 Trading Program, the designated representative of the unit shall submit to the Administrator a request to withdraw the unit effective as of midnight of December 31 of a specified calendar year, which date must be at least 4 years after December 31 of the year of the unit's entry into the TR SO_2 Group 1 Trading Program under § 97.641(h). The request shall be in a format prescribed by the Administrator and shall be submitted no later than 90 days before the requested effective date of withdrawal.

(b) *Conditions for withdrawal.* Before a TR SO_2 Group 1 opt-in unit covered by the request to withdraw may withdraw from the TR SO_2 Group 1 Trading Program, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the TR SO_2 Group 1 opt-in unit must meet the requirement to hold TR SO_2 Group 1 allowances under §§ 97.624 and 97.625 and cannot have any excess emissions.

(2) After the requirement under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the TR SO_2 Group 1 opt-in unit TR SO_2 Group 1 allowances equal in amount to and allocated for the same or a prior control period as any TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 opt-in unit under § 97.644 for any control period after the date on which the withdrawal is to be effective. If there are no other TR SO_2 Group 1 units at the source, the Administrator will close the compliance account, and the owners and operators of the TR SO_2 Group 1 opt-in unit may submit a TR SO_2 Group 1 allowance transfer for any remaining TR SO_2 Group 1 allowances to another Allowance Management System account in accordance with §§ 97.622 and 97.623.

(c) *Approving withdrawal.* (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of TR SO_2 Group 1 allowances required), the Administrator will issue a written approval of the request to withdraw, which will become effective as of midnight on December 31 of the calendar year for which the withdrawal was requested. The unit covered by the request shall continue to be a TR SO_2 Group 1 opt-in unit until the effective date of the withdrawal and shall comply with all requirements under the TR SO_2 Group 1 Trading Program concerning any control periods for which the unit is a TR SO_2 Group 1 opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the Administrator will issue a written disapproval of the request to withdraw. The unit covered by the request shall continue to be a TR SO_2 Group 1 opt-in unit.

(d) *Reapplication upon failure to meet conditions of withdrawal.* If the Administrator disapproves the request to withdraw, the designated representative of the unit may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(e) *Ability to reapply to the TR SO_2 Group 1 Trading Program.* Once a TR SO_2 Group 1 opt-in unit withdraws from the TR SO_2 Group 1 Trading Program, the designated representative may not submit another opt-in application under § 97.641 for such unit before the date that is 4 years after the date on which the withdrawal became effective.

§ 97.643 Change in regulatory status.

(a) *Notification.* If a TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604, then the designated representative of the unit shall notify the Administrator in writing of such change in the TR SO_2 Group 1 opt-in unit's regulatory status, within 30 days of such change.

(b) *Administrator's actions.* (1) If a TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604, the Administrator will deduct, from the compliance account of the source that includes the TR SO_2 Group 1 opt-in unit that becomes a TR SO_2 Group 1 unit under § 97.604, TR SO_2 Group 1 allowances equal in amount to and allocated for the same or a prior control period as:

(i) Any TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 opt-in unit under § 97.644 for any control period starting after the date on which the TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604; and

(ii) If the date on which the TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604 is not December 31, the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 opt-in unit under § 97.644 for the control period that includes the date on which the TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604—

(A) Multiplied by the ratio of the number of days, in the control period, starting with the date on which the TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604, divided by the total number of days in the control period, and

(B) Rounded to the nearest allowance.

(2) The designated representative shall ensure that the compliance account of the source that includes the TR SO_2 Group 1 opt-in unit that becomes a TR SO_2 Group 1 unit under § 97.604 contains the TR SO_2 Group 1 allowances necessary for completion of the deduction under paragraph (b)(1) of this section.

(3)(i) For control periods starting after the date on which the TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604, the TR SO_2 Group 1 opt-in unit will be allocated TR SO_2 Group 1 allowances in accordance with § 97.612.

(ii) If the date on which the TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604 is not December 31, the following amount of TR SO_2 Group 1 allowances will be allocated to the TR SO_2 Group 1 opt-in unit (as a TR SO_2 Group 1 unit) in accordance with § 97.612 for the control period that includes the date on which the TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604:

(A) The amount of TR SO_2 Group 1 allowances otherwise allocated to the TR SO_2 Group 1 opt-in unit (as a TR SO_2 Group 1 unit) in accordance with § 97.612 for the control period;

(B) Multiplied by the ratio of the number of days, in the control period, starting with the date on which the TR SO_2 Group 1 opt-in unit becomes a TR SO_2 Group 1 unit under § 97.604, divided by the total number of days in the control period; and

(C) Rounded to the nearest allowance.

§ 97.644 TR SO_2 Group 1 allowance allocations to TR SO_2 Group 1 opt-in units.

(a) *Timing requirements.* (1) When the TR opt-in application is approved for a unit under § 97.641(g), the Administrator will issue TR SO_2 Group 1 allowances and allocate them to the unit for the control period in which the unit enters the TR SO_2 Group 1 Trading Program under § 97.641(h), in accordance with paragraph (b) of this section.

(2) By no later than October 31 of the control period after the control period in which a TR SO_2 Group 1 opt-in unit enters the TR SO_2 Group 1 Trading Program under § 97.641(h) and October 31 of each year thereafter, the Administrator will issue TR SO_2 Group 1 allowances and allocate them to the TR SO_2 Group 1 opt-in unit for the control period that includes such allocation deadline and in which the unit is a TR SO_2 Group 1 opt-in unit, in accordance with paragraph (b) of this section.

(b) *Calculation of allocation.* For each control period for which a TR SO_2 Group 1 opt-in unit is to be allocated TR SO_2 Group 1 allowances, the Administrator will issue and allocate TR SO_2 Group 1 allowances in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the TR SO_2 Group 1 allowance allocation will be the lesser of:

(i) The TR SO_2 Group 1 opt-in unit's baseline heat input determined under § 97.641(g); or

(ii) The TR SO_2 Group 1 opt-in unit's heat input, as determined in accordance with §§ 97.630 through 97.635, for the immediately prior control period, except when the allocation is being calculated for the control period in which the TR SO_2 Group 1 opt-in unit enters the TR SO_2 Group 1 Trading Program under § 97.641(h).

(2) The SO_2 emission rate (in lb/mmBtu) used for calculating TR SO_2 Group 1 allowance allocations will be the lesser of:

(i) The TR SO_2 Group 1 opt-in unit's baseline SO_2 emission rate (in lb/mmBtu) determined under § 97.641(g) and multiplied by 70 percent; or

(ii) The most stringent State or Federal SO_2 emissions limitation applicable to the TR SO_2 Group 1 opt-in unit at any time during the control period for which TR SO_2 Group 1 allowances are to be allocated.

(3) The Administrator will issue TR SO_2 Group 1 allowances and allocate them to the TR SO_2 Group 1 opt-in unit in an amount equaling the heat input under paragraph (b)(1) of this section, multiplied by the SO_2 emission rate under paragraph (b)(2) of this section, divided by 2,000 lb/ton, and rounded to the nearest allowance.

(c) *Recordation.* (1) The Administrator will record, in the compliance account of the source that includes the TR SO_2 Group 1 opt-in unit, the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 opt-in unit under paragraph (a)(1) of this section.

(2) By December 1 of the control period after the control period in which a TR SO_2 Group 1 opt-in unit enters the TR SO_2 Group 1 Trading Program under § 97.641(h) and December 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the TR SO_2 Group 1 opt-in unit, the TR SO_2 Group 1 allowances allocated to the TR SO_2 Group 1 opt-in unit under paragraph (a)(2) of this section.

38. Part 97 is amended by adding subpart DDDDD to read as follows:

Subpart DDDDD—TR SO_2 Group 2 Trading Program

Sec.

Subpart DDDDD—TR SO_2 Group 2 Trading Program

§ 97.701 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Transport Rule (TR) SO_2 Group 2 Trading Program, under section 110 of the Clean Air Act and § 52.38(b) of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

§ 97.702 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor) of the United States Environmental Protection Agency, the Administrator's duly authorized representative under this subpart.

Allocate or allocation means, with regard to TR SO_2 Group 2 allowances, the determination by the Administrator of the amount of such TR SO_2 Group 2 allowances to be initially credited to a TR SO_2 Group 2 source or a new unit set-aside.

Allowable SO_2 emission rate means, with regard to a unit, the SO_2 emission rate limit that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, deductions, and transfers of TR SO_2 Group 2 allowances under the TR SO_2 Group 2 Trading Program. Such allowances are allocated, held, deducted, or transferred only as whole allowances. The Allowance Management System is a component of the CAMD Business System, which is the system used by the Administrator to handle TR SO_2 Group 2 allowances and data related to SO_2 emissions.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, holding, transfer, or deduction of TR SO_2 Group 2 allowances.

Allowance transfer deadline means, for a control period, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR SO_2 Group 2 allowance transfer must be submitted for recordation in a TR SO_2 Group 2 source's compliance account in order to be available for use in complying with the source's TR SO_2 Group 2 Annual emissions limitation for such control period in accordance with § 97.724.

Alternate designated representative means, for a TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the TR SO_2 Group 2 Trading Program. If the TR SO_2 Group 2 source is also subject to the Acid Rain Program, TR NO_X Annual Season Trading Program, or TR NO_X Ozone Season Trading Program, then this natural person shall be the same natural person as the alternate designated representative as defined in § 72.2 of this chapter, § 97.402, or § 97.502 respectively.

Authorized account representative means, with regard to a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of TR SO_2 Group 2 allowances held in the general account and, with regard to a TR SO_2 Group 2 source's compliance account, the designated representative of the source.

Automated data acquisition and handling system or DAHS means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, 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 this subpart.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

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.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president or the corporation in charge of a principal business function or any other person who performs similar policy or decision making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during 1990 or any year thereafter.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine—

(1) Operating as part of a cogeneration system; and

(2) Producing during the later of 1990 or the 12-month period starting on the date that the unit first produces electricity and during each calendar year after the later of 1990 or the calendar year in which the unit first produces electricity—

(i) For a topping-cycle unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel, except biomass if the unit is a boiler; and

(4) Provided that, if a topping-cycle unit is operated as part of a cogeneration system during a calendar year and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) of this definition, the topping-cycle unit shall be deemed to meet such requirement during that calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, 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; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated

duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) 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 § 97.705.

(i) For a unit that is a TR SO_2 Group 2 unit under § 97.704 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a TR SO_2 Group 2 unit under § 97.704 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 97.705, for a unit that is not a TR SO_2 Group 2 unit under § 97.704 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in introductory text of paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a TR SO_2 Group 2 unit under § 97.704.

(i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same source, such date shall remain the replaced unit's date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Commence operation means, with regard to a unit:

(1) To have begun any mechanical, chemical, or electronic process, including start-up of the unit's combustion chamber.

(2) For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(3) For a unit that is replaced by a unit at the same source after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the replaced unit's date of commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a TR SO_2 Group 2 source under this subpart, in which any TR SO_2 Group 2 allowance allocations for the TR SO_2 Group 2 units at the source are recorded and in which are held any TR SO_2 Group 2 allowances available for use for a control period in complying with the source's TR SO_2 Group 2 emissions limitation in accordance with § 97.724 and the TR SO_2 Group 2 assurance provisions in accordance with § 97.725.

Continuous emission monitoring system or CEMS means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of SO_2 emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 or CO_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§ 97.730 through 97.735. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A SO_2 monitoring system, consisting of a SO_2 pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of SO_2 emissions, in parts per million (ppm);

(3) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(4) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(5) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period starting January 1 of a calendar year, except as provided in § 97.706(c)(3), and ending on December 31 of the same year, inclusive.

Designated representative means, for a TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the TR SO_2 Group 2 Trading Program. If the TR SO_2 Group 2 source is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, or TR NO_X Ozone Season Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in § 72.2 of this chapter, § 97.402, or § 97.502 respectively.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart.

Excess emissions means any ton of SO_2 emitted from the TR SO_2 Group 2 units at a TR SO_2 Group 2 source during a control period that exceeds the TR SO_2 Group 2 emissions limitation for the source.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying §§ 97.704(b)(2)(i)(B), 97.704(b)(2)(ii)(B), and 97.704(b)(2)(iii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 1990 or any calendar year thereafter.

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a unit for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

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 generated by 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 no less 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 maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

Newly affected TR SO_2 Group 2 unit means a unit that was not a TR SO_2 Group 2 unit when it began operating but that thereafter becomes a TR SO_2 Group 2 unit.

Operate or operation means, with regard to a unit, to combust fuel.

Operator means any person who operates, controls, or supervises a TR SO_2 Group 2 unit or a TR SO_2 Group 2 source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means, with regard to a TR SO_2 Group 2 source or a TR SO_2 Group 2 unit at a source respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a TR SO_2 Group 2 unit at the source or the TR SO_2 Group 2 unit;

(2) Any holder of a leasehold interest in a TR SO_2 Group 2 unit at the source or the TR SO_2 Group 2 unit, provided that, 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) on the revenues or income from such TR SO_2 Group 2 unit;

(3) Any purchaser of power from a TR SO_2 Group 2 unit at the source or the TR SO_2 Group 2 unit under a life-of-the-unit, firm power contractual arrangement;

(4) Provided that, for purposes of applying the TR SO_2 Group 2 assurance provisions in §§ 97.706(c)(2) and 97.725, if one or more owners (as defined in paragraphs (1) through (3) of this definition) of one or more TR SO_2 Group 2 units in a State are wholly owned by another, common owner, all such owners shall be treated collectively as a single owner in the State.

Owner's assurance level means:

(1) With regard to a State and control period for which the State assurance level is exceeded as described in § 97.706(c)(2)(iii)(A) and not as described in § 97.706(c)(2)(iii)(B), the owner's share of the State SO_2 Group 2 trading budget with the one-year variability limit for the State for such control period; or

(2) With regard to a State and control period for which the State assurance level is exceeded as described in § 97.706(c)(2)(iii)(B), the owner's share of the State SO_2 Group 2 trading budget with the three-year variability limit for the State for such control period.

Owner's share means:

(1) With regard to a total amount of SO_2 emissions from all TR SO_2 Group 2 units in a State during a control period, the total tonnage of SO_2 emissions during such control period from all of the owner's TR SO_2 Group 2 units in the State;

(2) With regard to a State SO_2 Group 2 trading budget with a one-year variability limit for a control period, the amount (rounded to the nearest allowance) equal to the total amount of TR SO_2 Group 2 allowances allocated for such control period to all of the owner's TR SO_2 Group 2 units in the State, multiplied by the sum of the State SO_2 Group 2 trading budget under § 97.710(a) and the State's one-year variability limit under § 97.710(b) and divided by such State SO_2 Group 2 trading budget;

(3) With regard to a State SO_2 Group 2 trading budget with a three-year

variability limit for a control period, the amount (rounded to the nearest allowance) equal to the total amount of TR SO_2 Group 2 allowances allocated for such control period to all of the owner's TR SO_2 Group 2 units in the State, multiplied by the sum of the State SO_2 Group 2 trading budget under § 97.710(a) and the State's three-year variability limit under § 97.710(b) and divided by such State SO_2 Group 2 trading budget;

(4) Provided that, in the case of a unit with more than one owner, the amount of tonnage of SO_2 emissions and of TR SO_2 Group 2 allowances allocated for a control period, with regard to such unit, used in determining each owner's share shall be the amount (rounded to the nearest ton and the nearest allowance) equal to the unit's SO_2 emissions and allocation of such allowances, respectively, for such control period multiplied by the percentage of ownership in the unit that the owner's legal, equitable, leasehold, or contractual reservation or entitlement in the unit comprises as of December 31 of such control period;

(5) Provided that, where two or more units emit through a common stack that is the monitoring location from which SO_2 mass emissions are reported for a control period for a year, the amount of tonnage of each unit's SO_2 emissions used in determining each owner's share for such control period shall be:

(i) The amount (rounded to the nearest ton) of SO_2 emissions reported at the common stack multiplied by the quotient of such unit's heat input for such control period divided by the total heat input reported from the common stack for such control period;

(ii) An amount determined in accordance with a methodology that the Administrator determines is consistent with the purposes of this definition and whose adverse effect (if any) the Administrator determines will be *de minimis;* or

(iii) An amount approved by the Administrator in response to a petition for an alternative requirement submitted in accordance with § 97.735; and

(6) Provided that, in the case of a unit that operates during, but is allocated no TR SO_2 Group 2 allowances for, a control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of TR SO_2 Group 2 allowances for such control period equal to the lesser of—

(i) The unit's allowable SO_2 emission rate (in lb per MWe) applicable to such control period, multiplied by a capacity factor of 0.84 (if the unit is a coal-fired boiler), 0.15 (if the unit is a simple combustion turbine), or 0.66 (if the unit is a combined cycle turbine), multiplied by the unit's maximum hourly load as reported in accordance with this subpart and by 8,760 hours/control period, and divided by 2,000 lb/ton; or

(ii) For a unit listed in appendix A to this subpart, the sum of the unit's SO_2 emissions in the control period in the last three years during which the unit operated during the control period, divided by three.

Permanently retired means, with regard to a unit, a unit that is unavailable for service and that the unit's owners and operators do not expect to return to service in the future.

Permitting authority means "permitting authority" as defined in §§ 70.2 and 71.2 of this chapter.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to TR SO_2 Group 2 allowances, the moving of TR SO_2 Group 2 allowances by the Administrator into, out of, or between Allowance Management System accounts, 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 § 75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

(1) For a topping-cycle unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle unit, the use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a TR SO_2 Group 2 allowance, the unique identification number assigned to each TR SO_2 Group 2 allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a "solid waste incineration unit" as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of "major source", "stationary source", or "source" as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States or the District of Columbia that is subject to the TR SO_2 Group 2 Trading Program pursuant to § 52.38(c) of this chapter.

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;

(4) Provided that compliance with any "submission" or "service" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Topping-cycle unit means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means total energy of all forms supplied to a unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

$$LHV = HHV - 10.55 (W + 9H)$$

Where

LHV = lower heating value of the form of energy in Btu/lb,
HHV = higher heating value of the form of energy in Btu/lb,
W = weight % of moisture in the form of energy, and
H = weight % of hydrogen in the form of energy.

Total energy output means the sum of useful power and useful thermal energy produced by the unit.

TR NO_X Annual Trading Program means a multi-state NO_X air pollution control and emission reduction program established by the Administrator in accordance with subpart AAAAA and 52.37(a) of this chapter, as a means of mitigating interstate transport of fine particulates and NO_X.

TR NO_X Ozone Season Trading Program means a multi-state NO_X air pollution control and emission reduction program established by the Administrator in accordance with subpart BBBBB of this part and 52.37(b) of this chapter, as a means of mitigating interstate transport of ozone and NO_X.

TR SO_2 Group 2 allowance means a limited authorization issued and allocated by the Administrator under this subpart to emit one ton of SO_2 during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the TR SO_2 Group 2 Trading Program.

TR SO_2 Group 2 allowance deduction or *deduct TR SO_2 Group 2 allowances* means the permanent withdrawal of TR SO_2 Group 2 allowances by the Administrator from a compliance account, *e.g.,* in order to account for compliance with the TR SO_2 Group 2 emissions limitation or assurance provisions.

TR SO_2 Group 2 allowances held or *hold TR SO_2 Group 2 allowances* means the TR SO_2 Group 2 allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, TR SO_2 Group 2 allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, TR SO_2 Group 2 allowance transfer in accordance with this subpart.

TR SO_2 Group 2 emissions limitation means, for a TR SO_2 Group 2 source, the tonnage of SO_2 emissions authorized in a control period by the TR SO_2 Group 2 allowances available for deduction for the source under § 97.724(a) for such control period.

TR SO_2 Group 2 source means a source that includes one or more TR SO_2 Group 2 units.

TR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established by the Administrator in accordance with this subpart and 52.38(c) of this chapter, as a means of mitigating interstate transport of fine particulates and SO_2.

TR SO_2 Group 2 unit means a unit that is subject to the TR SO_2 Group 2 Trading Program under § 97.704.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or hour of unit operation means an hour in which a unit combusts any fuel.

Useful power means electricity or mechanical energy that a unit makes available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (*e.g.,* space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.,* in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 97.703 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit
CO_2—carbon dioxide
H_2O—water
hr—hour
kW—kilowatt electrical
kWh—kilowatt hour
lb—pound
mmBtu—million Btu
MWe—megawatt electrical
MWh—megawatt hour
NO_X—nitrogen oxides
O_2—oxygen
ppm—parts per million
scfh—standard cubic feet per hour
SO_2—sulfur dioxide
yr—year

§ 97.704 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State shall be TR SO_2 Group 2 units, and any source that includes one or more such units shall be a TR SO_2 Group 2 source, subject to the requirements of this subpart: Any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a TR SO_2 Group 2 unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a TR SO_2 Group 2 unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State that otherwise is a TR SO_2 Group 2 unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i), (b)(2)(i), or (b)(2)(ii) of this section shall not be a TR SO_2 Group 2 unit:

(1)(i) Any unit:

(A) Qualifying as a cogeneration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If a unit qualifies as a cogeneration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (b)(1)(i) of this section for at least one calendar year, but subsequently no longer meets such qualification and requirements, the unit shall become a TR SO_2 Group 2 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section.

(2)(i) Any unit commencing operation before January 1, 1985:

(A) Qualifying as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit; and

(B) With an average annual fuel consumption of fossil fuel for 1985–1987 less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years after 1990 less than 20 percent (on a Btu basis).

(ii) Any unit commencing operation on or after January 1, 1985:

(A) Qualifying as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit; and

(B) With an average annual fuel consumption of fossil fuel for the first 3 calendar years of operation less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years after 1990 less than 20 percent (on a Btu basis).

(iii) If a unit qualifies as a solid waste incineration unit during the later of 1990 or the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraph (b)(2)(i) or (ii) of this section for at least 3 consecutive calendar years, but subsequently no longer meets such qualification and requirements, the unit shall become a TR SO_2 Group 2 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 1990 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more.

(c) A certifying official of an owner or operator of any unit or other equipment may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR SO_2 Group 2 Trading Program to the unit or other equipment.

(1) *Petition content.* The petition shall be in writing and include the identification of the unit or other equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: "I am authorized to make this submission on behalf of the owners and operators of the unit or other equipment 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) *Response.* The Administrator will issue a written response to the petition and may request supplemental information determined by the Administrator to be relevant to such petition. The Administrator's determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR SO_2 Group 2 Trading Program to the unit or other equipment shall be binding on any permitting authority unless the Administrator determines that the petition or other documents or information provided in connection with the petition contained significant, relevant errors or omissions.

§ 97.705 Retired unit exemption.

(a)(1) Any TR SO_2 Group 2 unit that is permanently retired and is not a TR SO_2 Group 2 opt-in unit shall be exempt from § 97.706(b) and (c)(1), § 97.724, and §§ 97.730 through 97.735.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the TR SO_2 Group 2 unit is permanently retired. Within 30 days of the unit's permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of 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 before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the TR SO_2 Group 2 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 exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

§ 97.706 Standard requirements.

(a) *Designated representative requirements.* The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§ 97.713 through 97.718.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of each TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.730 through 97.735.

(2) The emissions data determined in accordance with §§ 97.730 through 97.735 shall be used to calculate allocations of TR SO_2 Group 2 allowances under §§ 97.711(a)(2) and (b) and 97.712 and to determine compliance with the TR SO_2 Group 2 emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.730 through 97.735 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) *SO_2 emissions requirements.* (1) TR SO_2 Group 2 emissions limitation. (i) As of the allowance transfer deadline for a control period, the owners and operators of each TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source shall hold, in the source's compliance account, TR SO_2 Group 2 allowances available for deduction for such control period under § 97.724(a) in an amount not less than the tons of total SO_2 emissions for such control period from all TR SO_2 Group 2 units at the source.

(ii) If a TR SO_2 Group 2 source emits SO_2 during any control period in excess of the TR SO_2 Group 2 emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR SO_2 Group 2 unit at the source shall hold the TR SO_2 Group 2 allowances required for deduction under § 97.724(d) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act; and

(B) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) *TR SO_2 Group 2 assurance provisions.* (i) If the total amount of SO_2 emissions from all TR SO_2 Group 2 units in a State during a control period in 2014 or any year thereafter exceeds the State assurance level as described in paragraph (c)(2)(iii) of this section, then each owner whose share of such SO_2 emissions during such control period exceeds the owner's assurance level for the State and such control period shall hold, in a compliance account designated by the owner in accordance with § 97.725(b)(4)(ii), TR SO_2 Group 2 allowances available for deduction for such control period under § 97.725(a) in an amount equal to the product, as determined by the Administrator in accordance with § 97.725(b), of multiplying—

(A) The quotient (rounded to the nearest whole number) of the amount by which the owner's share of such SO_2 emissions exceeds the owner's assurance level divided by the sum of the amounts, determined for all such owners, by which each owner's share of such SO_2 emissions exceeds that owner's assurance level; and

(B) The amount by which total SO_2 emissions for all TR SO_2 Group 2 units in the State for such control period exceed the State assurance level as determined in accordance with paragraph (c)(2)(iii) of this section.

(ii) The owner shall hold the TR SO_2 Group 2 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) The total amount of SO_2 emissions from all TR SO_2 Group 2 units in a State during a control period in 2014 or any year thereafter exceeds the State assurance level:

(A) If such total amount of SO_2 emissions exceeds the sum, for such control period, of the State SO_2 Group 2 trading budget and the State's one-year variability limit under § 97.710(b); or

(B) If, with regard to a control period in 2016 or any year thereafter, the sum, divided by three, of such total amount of SO_2 emissions and the total amounts of SO_2 emissions from all TR SO_2 Group 2 units in the State during the control periods in the immediately preceding two years exceeds the sum, for such control period, of the State SO_2 Group 2 trading budget and the State's three-year variability limit under § 97.710(b);

(C) Provided that the amount by which such total amount of SO_2 emissions exceeds the State assurance level shall be the greater of the amounts of the exceedance calculated under paragraph (c)(2)(iii)(A) of this section and under paragraph (c)(2)(iii)(B) of this section.

(iv) It shall not be a violation of this subpart or of the Clean Air Act if the total amount of SO_2 emissions from all TR SO_2 Group 2 units in a State during a control period exceeds the State assurance level or if an owner's share of total SO_2 emissions from the TR SO_2 Group 2 units in a State during a control period exceeds the owner's assurance level.

(v) To the extent an owner fails to hold TR SO_2 Group 2 allowances for a control period in accordance with paragraphs (c)(2)(i) and (ii) of this section,

(A) The owner shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR SO_2 Group 2 allowance that the owner fails to hold for a control period in accordance with paragraphs (c)(2)(i) and (ii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) *Compliance periods.* A TR SO_2 Group 2 unit shall be subject to the requirements:

(i) Under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2012 or the deadline for meeting the unit's monitor certification requirements under § 97.730(b) and for each control period thereafter; and

(ii) Under paragraph (c)(2) of this section for the control period starting on the later of January 1, 2014 or the deadline for meeting the unit's monitor certification requirements under § 97.730(b) and for each control period thereafter.

(4) *Vintage of deducted allowances.* A TR SO_2 Group 2 allowance shall not be deducted, for compliance with the requirements under paragraphs (c)(1) and (2) of this section, for a control period in a calendar year before the year for which the TR SO_2 Group 2 allowance was allocated.

(5) *Allowance Management System requirements.* Each TR SO_2 Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) *Limited authorization.* (i) A TR SO_2 Group 2 allowance is a limited authorization to emit one ton of SO_2 in accordance with the TR SO_2 Group 2 Trading Program.

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) *Property right.* A TR SO_2 Group 2 allowance does not constitute a property right.

(d) *Title V Permit requirements.* (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR SO_2 Group 2 allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report SO_2 emissions using a continuous emission monitoring system (under §§ 75.10, 75.11, and 75.16 of this chapter), an excepted monitoring system (under appendix D to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.730 through 97.735 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) *Additional recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of each TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 97.716 for the designated representative for the source and each TR SO_2 Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; 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 certificate of representation under § 97.716 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR SO_2 Group 2 Trading Program, including any monitoring plans and monitoring system certification and recertification applications.

(2) The designated representative of a TR SO_2 Group 2 source and each TR SO_2 Group 2 unit at the source shall make all submissions required under the TR SO_2 Group 2 Trading Program, including any submissions required for compliance with the TR SO_2 Group 2 assurance provisions. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) *Liability.* (1) Any provision of the TR SO_2 Group 2 Trading Program that applies to a TR SO_2 Group 2 source or the designated representative of a TR SO_2 Group 2 source shall also apply to the owners and operators of such source and of the TR SO_2 Group 2 units at the source.

(2) Any provision of the TR SO_2 Group 2 Trading Program that applies to a TR SO_2 Group 2 unit or the designated representative of a TR SO_2 Group 2 unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the TR SO_2 Group 2 Trading Program or exemption under § 97.705 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR SO_2 Group 2 source or TR SO_2 Group 2 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 97.707 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the TR SO_2 Group 2 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 TR SO_2 Group 2 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 TR SO_2 Group 2 Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 97.708 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the TR SO_2 Group 2 Trading Program are set forth in part 78 of this chapter.

§ 97.709 [Reserved]

§ 97.710 State SO_2 Group 2 trading budgets, new-unit set-asides, and variability limits.

(a) The State SO_2 Group 2 trading budgets and new-unit set-asides for allocations of TR SO_2 Group 2 allowances for the control periods in 2012 and thereafter are as follows:

State	SO_2 group 2 trading budget (tons) *	New-unit set-aside (tons)
	For 2012 and thereafter	For 2012 and thereafter
Alabama	161,871	4,856
Connecticut	3,059	92
Delaware	7,784	234
District of Columbia	337	10
Florida	161,739	4,852
Kansas	57,275	1,718
Louisiana	90,477	2,714
Maryland	39,665	1,190
Massachusetts	7,902	237
Minnesota	47,101	1,413
Nebraska	71,598	2,148
New Jersey	11,291	339
South Carolina	116,483	3,494
Total	776,582	23,297

* Without variability limits.

(b) The States' one-year and three-year variability limits for the State SO_2 Group 2 trading budgets for the control periods in 2014 and thereafter are as follows:

State	One-year variability limits	Three-year variability limits
	2014 and thereafter (tons)	2016 and thereafter (tons)
Alabama	16,187	9,346
Connecticut	1,700	981
Delaware	1,700	981
District of Columbia	1,700	981
Florida	16,174	9,338
Kansas	5,728	3,307
Louisiana	9,048	5,224
Maryland	3,967	2,290
Massachusetts	1,700	981
Minnesota	4,710	2,719
Nebraska	7,160	4,134
New Jersey	1,700	981
South Carolina	11,648	6,725

§ 97.711 Timing requirements for TR SO_2 Group 2 allowance allocations.

(a) *Existing units.* (1) TR SO_2 Group 2 allowances are allocated, for the control periods in 2012 and each year thereafter, as set forth in appendix A to this subpart. Listing a unit in such appendix does not constitute a determination that the unit is a TR SO_2 Group 2 unit, and not listing a unit in such appendix does not constitute a determination that the unit is not a TR SO_2 Group 2 unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit listed in appendix A to this subpart as being allocated TR SO_2 Group 2 allowances does not operate, starting after 2011, during the control period in three consecutive years, such unit will not be allocated the TR SO_2 Group 2 allowances set forth in appendix A to this subpart for the unit for the control periods in the seventh year after the first such year and in each year after that seventh year. All TR SO_2 Group 2 allowances that would otherwise have been allocated to such unit will be allocated to the new unit set-aside for the respective years involved. If such unit resumes operation, the Administrator will allocate TR SO_2 Group 2 allowances to the unit in accordance with paragraph (b) of this section.

(b) *New units.* (1) By July 1, 2012, and July 1 of each year thereafter, the Administrator will calculate the TR SO_2 Group 2 allowance allocation for each TR SO_2 Group 2 unit, in accordance with § 97.712, for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of availability of the results of the calculations.

(2) For each notice of data availability required in paragraph (b)(1) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations are in accordance with § 97.712 and §§ 97.706(b)(2) and 97.730 through 97.735.

(ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By September 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.

(c) *Units that are not TR SO_2 Group 2 units.* For each control period in 2012 and thereafter, if the Administrator determines that TR SO_2 Group 2 allowances were allocated under paragraph (a) of this section for the control period to a recipient that is not actually a TR SO_2 Group 2 unit under § 97.704 as of January 1, 2012, or whose deadline for meeting monitor certification requirements under § 97.730(b)(1) and (2) is after January 1, 2012, or if the Administrator determines that TR SO_2 Group 2 allowances were allocated under paragraph (b) of this section and § 97.712 for the control period to a recipient that is not actually a TR SO_2 Group 2 unit under § 97.704 as of January 1 of the control period, then the Administrator will notify the designated representative and will act in accordance with the following procedures:

(1) Except as provided in paragraph (c)(2) or (3) of this section, the Administrator will not record such TR SO_2 Group 2 allowances under § 97.721.

(2) If the Administrator already recorded such TR SO_2 Group 2 allowances under § 97.721 and if the Administrator makes such determination before making deductions for the source that includes such recipient under § 97.724(b) for such control period, then the Administrator will deduct from the account in which such TR SO_2 Group 2 allowances were recorded an amount of TR SO_2 Group 2 allowances allocated for the same or a prior control period equal to the amount of such already recorded TR SO_2 Group 2 allowances. The authorized account representative shall ensure that there are sufficient TR SO_2 Group 2 allowances in such account for completion of the deduction.

(3) If the Administrator already recorded such TR SO_2 Group 2 allowances under § 97.721 and if the Administrator makes such determination after making deductions for the source that includes such recipient under § 97.724(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded TR SO_2 Group 2 allowances.

(4) The Administrator will transfer the TR SO_2 Group 2 allowances that are not recorded, or that are deducted, in accordance with paragraphs (c)(1) and (2) of this section to the new unit set-aside, for the State in which such recipient is located, for the control period in the year of such transfer if the notice required in paragraph (b)(1) of this section for the control period in that year has not been promulgated or, such notice has been promulgated, in the next year.

§ 97.712 TR SO_2 Group 2 allowance allocations for new units.

(a) For each control period in 2012 and thereafter, the Administrator will allocate, in accordance with the following procedures, TR SO_2 Group 2 allowances to TR SO_2 Group 2 units in a State that are not listed in appendix A to this subpart, to TR SO_2 Group 2 units that are so listed and whose allocation of SO_2 Group 2 allowances for such control period is covered by § 97.711(c)(1) or (2), and to TR SO_2 Group 2 units that are so listed and, pursuant to § 97.711(a)(2), are not allocated TR SO_2 Group 2 allowances for such control period but that operate during the immediately preceding control period:

(1) The Administrator will establish a separate new unit set-aside for each State for each control period in a given year. Each new unit set-aside will be allocated TR SO_2 Group 2 allowances in an amount equal to the applicable amount of tons of SO_2 emissions as set forth in § 97.710(a). Each new unit set-aside will be allocated additional TR SO_2 Group 2 allowances in accordance with § 97.711(a)(2) and (c)(4).

(2) The designated representative of such TR SO_2 Group 2 unit may submit to the Administrator a request, in a format prescribed by the Administrator, to be allocated TR SO_2 Group 2 allowances for a control period, starting with the later of the control period in 2012, the first control period after the control period in which the TR SO_2 Group 2 unit commences commercial operation (for a unit not listed in appendix A to this subpart), or the first control period after the control period in which the unit resumes operation (for a unit listed in appendix A of this subpart) and for each subsequent control period.

(i) The request must be submitted on or before May 1 of the first control period for which TR SO_2 Group 2 allowances are sought and after the date on which the TR SO_2 Group 2 unit commences commercial operation (for a unit not listed in appendix A of this subpart) or on which the unit resumes operation (for a unit listed in appendix A of this subpart).

(ii) For each control period for which an allocation is sought, the request must be for TR SO_2 Group 2 allowances in an amount equal to the unit's total tons of SO_2 emissions during the immediately preceding control period.

(3) The Administrator will review each TR SO_2 Group 2 allowance allocation request under paragraph (a)(2) of this section and will accept the request only if it meets the requirements of paragraph (a)(2) of this section. The Administrator will allocate TR SO_2 Group 2 allowances for each control period pursuant to an accepted request as follows:

(i) After May 1 of such control period, the Administrator will determine the sum of the TR SO_2 Group 2 allowances requested in all accepted allowance allocation requests for such control period.

(ii) If the amount of TR SO_2 Group 2 allowances in the new unit set-aside for such control period is greater than or equal to the sum under paragraph (a)(3)(i) of this section, then the Administrator will allocate the amount of TR SO_2 Group 2 allowances requested to each TR SO_2 Group 2 unit covered by an accepted allowance allocation request.

(iii) If the amount of TR SO_2 Group 2 allowances in the new unit set-aside for such control period is less than the sum under paragraph (a)(3)(i) of this section, then the Administrator will allocate to each TR SO_2 Group 2 unit covered by an accepted allowance allocation request the amount of the TR SO_2 Group 2 allowances requested, multiplied by the amount of TR SO_2 Group 2 allowances in the new unit set-aside for such control period, divided by the sum determined under paragraph (a)(3)(i) of this section, and rounded to the nearest allowance.

(iv) The Administrator will notify, through the promulgation of the notices of data availability described in § 97.711(b), each designated representative that submitted an allowance allocation request of the amount of TR SO_2 Group 2 allowances (if any) allocated for such control period to the TR SO_2 Group 2 unit covered by the request.

(b) If, after completion of the procedures under paragraph (a)(4) of this section for a control period, any unallocated TR SO_2 Group 2 allowances remain in the new unit set-aside under paragraph (a) of this section for a State for such control period, the Administrator will allocate to each TR SO_2 Group 2 unit that is in the State, is listed in appendix A to this subpart, and continues to be allocated TR SO_2 Group 2 allowances for such control period in accordance with § 97.711(a)(2), an amount of TR SO_2 Group 2 allowances equal to the following: The total amount of such remaining unallocated TR SO_2 Group 2 allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.711(a) for such control period, divided by the remainder of the amount of tons in the applicable State SO_2 Group 2 trading budget minus the amount of tons in such new unit set-aside, and rounded to the nearest allowance.

§ 97.713 Authorization of designated representative and alternate designated representative.

(a) Except as provided under § 97.715, each TR SO_2 Group 2 source, including all TR SO_2 Group 2 units at the source, shall have one and only one designated representative, with regard to all matters under the TR SO_2 Group 2 Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR SO_2 Group 2 units at the source and shall act in accordance with the certification statement in § 97.716(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.716:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each TR SO_2 Group 2 unit at the source in all matters pertaining to the TR SO_2 Group 2 Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each TR SO_2 Group 2 unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under § 97.715, each TR SO_2 Group 2 source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR SO_2 Group 2 units at the source and shall act in accordance with the certification statement in § 97.716(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 97.716,

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each TR SO_2 Group 2 unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit.

(c) Except in this section, § 97.702, and §§ 97.714 through 97.718, whenever the term "designated representative" is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 97.714 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under § 97.718 concerning delegation of authority to make submissions, each submission under the TR SO_2 Group 2 Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each TR SO_2 Group 2 source and TR SO_2 Group 2 unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or 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."

(b) The Administrator will accept or act on a submission made for a TR SO_2 Group 2 source or a TR SO_2 Group 2 unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 97.718.

§ 97.715 Changing designated representative and alternate designated representative; changes in owners and operators.

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.716. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the TR SO_2 Group 2 source and the TR SO_2 Group 2 units at the source.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.716. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the TR SO_2 Group 2 source and the TR SO_2 Group 2 units at the source.

(c) *Changes in owners and operators.* (1) In the event an owner or operator of a TR SO_2 Group 2 source or a TR SO_2 Group 2 unit is not included in the list of owners and operators in the certificate of representation under § 97.716, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a TR SO_2 Group 2 source or a TR SO_2 Group 2 unit, including the addition of a new owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under § 97.716 amending the list of owners and operators to include the change.

§ 97.716 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the TR SO_2 Group 2 source, and each TR SO_2 Group 2 unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe rounded to the nearest tenth) of each generator served by each such unit, and actual or projected date of commencement of commercial operation.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the TR SO_2 Group 2 source and of each TR SO_2 Group 2 unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) "I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each TR SO_2 Group 2 unit at the source."

(ii) "I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR SO_2 Group 2 Trading Program on behalf of the owners and operators of the source and of each TR SO_2 Group 2 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 order issued to me by the Administrator regarding the source or unit."

(iii) "Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a TR SO_2 Group 2 unit, or where a utility or industrial customer purchases power from a TR SO_2 Group 2 unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each TR SO_2 Group 2 unit at the source; and TR SO_2 Group 2 allowances and proceeds of transactions involving TR SO_2 Group 2 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of TR SO_2 Group 2 allowances by contract, TR SO_2 Group 2 allowances and proceeds of transactions involving TR SO_2 Group 2 allowances will be deemed to be held or distributed in accordance with the contract."

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.717 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under § 97.716 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 97.716 is received by the Administrator.

(b) Except as provided in § 97.715(a) or (b), no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the TR SO_2 Group 2 Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of TR SO_2 Group 2 allowance transfers.

§ 97.718 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.718(d) shall be deemed to be an electronic submission by me."

(ii) "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.718(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.718 is terminated.".

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

§ 97.719 [Reserved]

§ 97.720 Establishment of Allowance Management System accounts.

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under § 97.716, the Administrator will establish a compliance account for the TR SO_2 Group 2 source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *General accounts*—(1) *Application for general account.* (i) Any person may apply to open a general account, for the purpose of holding and transferring TR SO_2 Group 2 allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to TR SO_2 Group 2 allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the TR SO_2 Group 2 allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to TR SO_2 Group 2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR SO_2 Group 2 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 regarding the general account."

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of authorized account representative and alternate authorized account representative.* (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to TR SO_2 Group 2 allowances held in the general account in all matters pertaining to the TR SO_2 Group 2 Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to TR SO_2 Group 2 allowances held in the general account shall be bound by any order or decision issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (b)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to TR SO_2 Group 2 allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the TR SO_2 Group 2 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."

(iii) Except in this section, whenever the term "authorized account representative" is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) *Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.* (i) The authorized account representative of 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 authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the TR SO_2 Group 2 allowances in the general account.

(ii) The alternate authorized account representative of 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 authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the TR SO_2 Group 2 allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to TR SO_2 Group 2 allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to SO_2 Group 2 allowances in the general account, including the addition of a new person, the authorized account representative or any alternate 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 TR SO_2 Group 2 allowances in the general account to include the change.

(4) *Objections concerning authorized account representative and alternate authorized account representative.* (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)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the TR SO_2 Group 2 Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of TR SO_2 Group 2 allowance transfers.

(5) *Delegation by authorized account representative and alternate authorized account representative.* (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (b)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (b)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.720(b)(5)(iv) shall be deemed to be an electronic submission by me."; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.720(b)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.720(b)(5) is terminated.".

(iv) A notice of delegation submitted under paragraph (b)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (b)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (b)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6)(i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted TR SO_2 Group 2 allowance transfer under § 97.722 for any TR SO_2 Group 2 allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no TR SO_2 Group 2 allowance transfers to or from the account for a 12-month period or longer and does not contain any TR SO_2 Group 2 allowances, the Administrator may notify the authorized account representative for the account that the account will be closed 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 TR SO_2 Group 2 allowance transfer under § 97.722 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

(d) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of an Allowance Management System account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of TR SO_2 Group 2 allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 97.714(a) and 97.718 or paragraphs (b)(2)(ii) and (b)(5) of this section.

§ 97.721 Recordation of TR SO_2 Group 2 allowance allocations.

(a) By September 1, 2011, the Administrator will record in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated for the TR SO_2 Group 2 units at the source in accordance with §§ 97.711(a) for the control periods in 2012, 2013, and 2014.

(b) By June 1, 2012 and June 1 of each year thereafter, the Administrator will record in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated for the TR SO_2 Group 2 units at the source in accordance with § 97.711(a) for the control period in the third year after the year of the applicable recordation deadline under this paragraph.

(c) By September 1, 2012 and September 1 of each year thereafter, the Administrator will record in each TR SO_2 Group 2 source's compliance account the TR SO_2 Group 2 allowances allocated for the TR SO_2 Group 2 units at the source in accordance with § 97.712 for the control period in the year of the applicable recordation deadline under this paragraph.

(d) When recording the allocation of TR SO_2 Group 2 allowances for a TR SO_2 Group 2 unit in a compliance account, the Administrator will assign each TR SO_2 Group 2 allowance a unique identification number that will include digits identifying the year of the control period for which the TR SO_2 Group 2 allowance is allocated.

§ 97.722 Submission of TR SO_2 Group 2 allowance transfers.

(a) An authorized account representative seeking recordation of a TR SO_2 Group 2 allowance transfer shall submit the transfer to the Administrator.

(b) A TR SO_2 Group 2 allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each TR SO_2 Group 2 allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each TR SO_2 Group 2 allowance identified by serial number in the transfer.

§ 97.723 Recordation of TR SO_2 Group 2 allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a TR SO_2 Group 2 allowance transfer, the Administrator will record a TR SO_2 Group 2 allowance transfer by moving each TR SO_2 Group 2 allowance from the transferor account to the transferee account as specified by the request, provided that the transfer is correctly submitted under § 97.722.

(b)(1) A TR SO_2 Group 2 allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any TR SO_2 Group 2 allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 97.724 for the control period immediately before such allowance transfer deadline.

(2) A TR SO_2 Group 2 allowance transfer that is submitted for recordation after the deadline for holding TR SO_2 Group 2 allowances described in § 97.725(b)(5) and that includes any TR SO_2 Group 2 allowances allocated for a control period before the year of such deadline will not be recorded until after the Administrator completes the deductions under § 97.725 for the control period immediately before the year of such deadline.

(c) Where a TR SO_2 Group 2 allowance transfer is not correctly submitted under § 97.722, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a TR SO_2 Group 2 allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a TR SO_2 Group 2 allowance transfer that is not correctly submitted under § 97.722, the Administrator will notify the 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.

§ 97.724 Compliance with TR SO_2 Group 2 emissions limitation.

(a) *Availability for deduction for compliance.* TR SO_2 Group 2 allowances are available to be deducted for compliance with a source's TR SO_2 Group 2 emissions limitation for a control period in a given year only if the TR SO_2 Group 2 allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in the source's compliance account as of the allowance transfer deadline for such control period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 97.723, of TR SO_2 Group 2 allowance transfers submitted by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account TR SO_2 Group 2 allowances available under paragraph (a) of this section in order to determine whether the source meets the TR SO_2 Group 2 emissions limitation for such control period, as follows:

(1) Until the amount of TR SO_2 Group 2 allowances deducted equals the number of tons of total SO_2 emissions from all TR SO_2 Group 2 units at the source for such control period; or

(2) If there are insufficient TR SO_2 Group 2 allowances to complete the deductions in paragraph (b)(1) of this section, until no more TR SO_2 Group 2 allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of TR* SO_2 *Group 2 allowances by serial number.* The authorized account representative for a source's compliance account may request that specific TR SO_2 Group 2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the TR SO_2 Group 2 source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR SO_2 Group 2 allowances under paragraph (b) or (d) of this section from the source's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR SO_2 Group 2 allowances in such request, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any TR SO_2 Group 2 allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR SO_2 Group 2 allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Deductions for excess emissions.* After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the TR SO_2 Group 2 source has excess emissions, the Administrator will deduct from the source's compliance account an amount of TR SO_2 Group 2 allowances, allocated for the control period in the immediately following year, equal to two times the number of tons of the source's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.725 Compliance with TR SO_2 Group 2 assurance provisions.

(a) *Availability for deduction.* TR SO_2 Group 2 allowances are available to be deducted for compliance with the TR SO_2 Group 2 assurance provisions for a control period in a given year by an owner of one or more TR SO_2 Group 2 units in a State only if the TR SO_2 Group 2 allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in a compliance account, designated by the owner in accordance with paragraph (b)(4)(ii) of this section,

of one of the owner's TR SO_2 Group 2 sources in the State as of the deadline established in paragraph (b)(5) of this section.

(b) *Deductions for compliance.* The Administrator will deduct TR SO_2 Group 2 allowances available under paragraph (a) of this section for compliance with the TR SO_2 Group 2 assurance provisions for a State for a control period in a given year in accordance with the following procedures:

(1) By June 1, 2015 and June 1 of each year thereafter, the Administrator will:

(i) Calculate, separately for each State, the total amount of SO_2 emissions from all TR SO_2 Group 2 units in the State during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total amount of NO_X emissions exceeds the State assurance level as described in § 97.706(c)(2)(iii); and

(ii) Promulgate a notice of availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the SO_2 emissions for each TR SO_2 Group 2 unit and of the amounts described in §§ 97.706(c)(2)(iii)(A) and (B) for each State.

(2) The Administrator will provide an opportunity for submission of objections to the calculations referenced by each notice described in paragraph (b)(1) of this section.

(i) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations for each TR SO_2 Group 2 unit and each State for the control period in the year involved are in accordance with § 97.706(c)(2)(iii) and §§ 97.706(b) and 97.730 through 97.735.

(ii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By August 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i) of this section.

(3) For each notice of data availability required in paragraph (b)(2)(ii) of this section and for any State identified in such notice as having TR SO_2 Group 2 sources with total SO_2 emissions exceeding the State assurance level for a control period, as described in § 97.706(c)(2)(iii):

(i) By August 15 immediately after the promulgation of such notice, the designated representative of each TR SO_2 Group 2 source in each such State shall submit a statement, in a format prescribed by the Administrator:

(A) Listing all the owners of each TR SO_2 Group 2 unit at the source, explaining how the selection of each owner for inclusion on the list is consistent with the definition of "owner" in § 97.702, and listing, separately for each unit, the percentage of the legal, equitable, leasehold, or contractual reservation or entitlement for each such owner as of midnight of December 31 of the control period in the year involved; and

(B) For each TR SO_2 Group 2 unit at the source that operates during, but is allocated no TR SO_2 Group 2 allowances for, the control period in the year involved, identifying whether the unit is a coal-fired boiler, simple combustion turbine, or combined cycle turbine cycle and providing the unit's allowable SO_2 emission rate for such control period.

(ii) By September 15 immediately after the promulgation of such notice, the Administrator will calculate, for each such State and each owner of one or more TR SO_2 Group 2 units in the State and for the control period in the year involved, each owner's share of the total SO_2 emissions from all TR SO_2 Group 2 units in the State, each owner's assurance level, and the amount (if any) of TR SO_2 Group 2 allowances that each owner must hold in accordance with the calculation formula in § 97.706(c)(2)(i) and will promulgate a notice of availability of the results of these calculations.

(iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(3)(ii) of this section.

(A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations for each owner for the control period in the year involved are consistent with the SO_2 emissions for the relevant TR SO_2 Group 2 units as set forth in the notice required in paragraph (b)(2)(ii) of this section, the definitions of "owner", "owner's assurance level", and "owner's share" in § 97.702, and the calculation formula in § 97.706(c)(2)(i) and shall not raise any issues about any data used in the notice of data availability required in paragraph (b)(2)(ii) of this section.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are consistent with the data and provisions referenced in paragraph (b)(3)(iii)(A) of this section. By November 15 immediately after the promulgation of such notice, the Administrator will promulgate a notice of availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(3)(iii)(A) of this section.

(4) By December 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section:

(i) Each owner identified, in such notice, as owning one or more TR SO_2 Group 2 units in a State and as being required to hold TR SO_2 Group 2 allowances shall designate the compliance account of one of the sources at which such unit or units are located to hold such required TR SO_2 Group 2 allowances;

(ii) The authorized account representative for the compliance account designated under paragraph (b)(4)(i) of this section shall submit to the Administrator a statement, in a format prescribed by the Administrator, making this designation.

(5)(i) As of midnight of December 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section, each owner described in paragraph (b)(4)(i) of this section shall hold in the compliance account designated by the owner in accordance with paragraph (b)(4)(ii) of this section the total amount of TR SO_2 Group 2 allowances, available for deduction under paragraph (a) of this section, equal to the amount the owner is required to hold as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(5)(i) of this section, if December 15 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(6) After December 15 (or the date described in paragraph (b)(5)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(3)(iii)(B) of this section and after the recordation, in accordance with § 97.723, of TR SO_2 Group 2 allowance transfers submitted by midnight of such date, the Administrator will deduct from each compliance account designated in accordance with paragraph (b)(4)(ii) of this section, TR SO_2 Group 2 allowances available under paragraph (a) of this section, as follows:

(i) Until the amount of TR SO_2 Group 2 allowances deducted equals the amount that the owner designating the compliance account is required to hold as calculated by the Administrator and referenced in the notice required in paragraph (b)(3)(iii)(B) of this section; or

(ii) If there are insufficient TR SO_2 Group 2 allowances to complete the deductions in paragraph (b)(6)(i) of this section, until no more TR SO_2 Group 2 allowances available under paragraph (a) of this section remain in the compliance account.

(7) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notices of data availability required in paragraphs (b)(2)(ii) and (b)(3)(iii)(B) of this section respectively for a control period, of any data used in making the calculations referenced in such notice, the amount of TR SO_2 Group 2 allowances that each owner is required to hold in accordance with § 97.706(c)(2)(i) for the control period in the year involved shall continue to be such amount as calculated by the Administrator and referenced in such notice required in paragraph (b)(3)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of TR SO_2 Group 2 allowances that owners are required to hold in accordance with the calculation formula in § 97.706(c)(2)(i) for the control period in the year involved with regard to the State involved, provided that—

(A) With regard to such litigation involving such notice required in paragraph (b)(2)(ii) of this section, such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(ii) of this section; and

(B) With regard to such litigation involving such notice required in paragraph (b)(3)(iii) of this section, such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(3)(iii) of this section.

(ii) If any such data are revised by the owners and operators of a source whose designated representative submitted such data under paragraph (b)(3)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of TR SO_2 Group 2 allowances that owners are required to hold in accordance with the calculation formula in § 97.706(c)(2)(i) for the control period in the year involved with regard to the State involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(3)(iii)(B) of this section.

(iii) If the revised data are used to recalculate, in accordance with paragraphs (b)(7)(i) and (b)(7)(ii) of this section, the amount of TR SO_2 Group 2 allowances that an owner is required to hold for the control period in the year involved with regard to the State involved—

(A) Where the amount of TR SO_2 Group 2 allowances that an owner is required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owner shall hold the additional amount of TR SO_2 Group 2 allowances in the compliance account designated by the owner in accordance with paragraph (b)(4)(ii) of this section. The owner's failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owner's failure to hold such additional amount, as required, as of the new deadline shall be a violation of the Clean Air Act. Each TR SO_2 Group 2 allowance that the owner fails to hold as required as of the new deadline, and each day in the control period in the year involved, shall be a separate violation of the Clean Air Act. After such deadline, the Administrator will make the appropriate deductions from the compliance account.

(B) For an owner for which the amount of TR SO_2 Group 2 allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in the compliance account that the owner designated in accordance with paragraph (b)(4)(ii) of this section, an amount of TR SO_2 Group 2 allowances equal to the amount of the decrease to the extent such amount was previously deducted from the compliance account under paragraph (b)(6) of this section (and has not already been restored to the compliance account) for the control period in the year involved.

(C) Each TR SO_2 Group 2 allowance held and deducted under paragraph (b)(7)(iii)(A) of this section, or recorded under paragraph (b)(7)(iii)(B) of this section, as a result of recalculation of requirements under the TR SO_2 Group 2 assurance provisions for a control period in a given year must be a TR SO_2 Group 2 allowance allocated for a control period in the same or a prior year.

(c)(1) *Identification of TR SO_2 Group 2 allowances by serial number.* The authorized account representative for each source's compliance account designated in accordance with paragraph (b)(4)(ii) of this section may request that specific TR SO_2 Group 2 allowances, identified by serial number, in the compliance account be deducted in accordance with paragraph (b)(6) or (7) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance-holding deadline described in paragraph (b)(5) of this section and include, in a format prescribed by the Administrator, the identification of the compliance account and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct TR SO_2 Group 2 allowances under paragraphs (b)(6) and (7) of this section from each source's compliance account designated under paragraph (b)(4)(ii) of this section in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR SO_2 Group 2 allowances in such request, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any TR SO_2 Group 2 allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR SO_2 Group 2 allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraph (b) of this section.

§ 97.726 Banking.

(a) A TR SO_2 Group 2 allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any TR SO_2 Group 2 allowance that is held in a compliance account or a general account will remain in such account unless and until the TR SO_2 Group 2 allowance is deducted or transferred under § 97.711(c), § 97.723, § 97.724, § 97.725, 97.727, 97.728, 97.742, or 97.743.

§ 97.727 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.728 Administrator's action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the TR SO_2 Group 2 Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct TR SO_2 Group 2 allowances from or transfer TR SO_2 Group 2 allowances to a source's compliance account based on the information in a submission, as adjusted under paragraph (a)(1) of this section, and record such deductions and transfers.

§ 97.729 [Reserved]

§ 97.730 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a TR SO_2 Group 2 unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subparts F and G of part 75 of this chapter. For purposes of applying such requirements, the definitions in § 97.702 and in § 72.2 of this chapter shall apply, the terms "affected unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") in part 75 of this chapter shall be deemed to refer to the terms "TR SO_2 Group 2 unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") respectively as defined in § 97.702, and the term "newly affected unit" shall be deemed to mean "newly affected TR SO_2 Group 2 unit". The owner or operator of a unit that is not a TR SO_2 Group 2 unit but that is monitored under § 75.16(b)(2) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a TR SO_2 Group 2 unit.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each TR SO_2 Group 2 unit shall:

(1) Install all monitoring systems required under this subpart for monitoring SO_2 mass emissions and individual unit heat input (including all systems required to monitor SO_2 concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.11 and 75.16 of this chapter);

(2) Successfully complete all certification tests required under § 97.731 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) Compliance deadlines. Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a TR SO_2 Group 2 unit that commences commercial operation before July 1, 2011, by January 1, 2012.

(2) For the owner or operator of a TR SO_2 Group 2 unit that commences commercial operation on or after July 1, 2011, by the later of the following dates:

(i) January 1, 2012; or

(ii) 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation.

(3) For the owner or operator of a TR SO_2 Group 2 unit for which construction of a new stack or flue or installation of add-on SO_2 emission controls is completed after the applicable deadline under paragraph (b)(1) or (2) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on SO_2 emissions controls.

(4) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved, by the date specified in § 97.741(c).

(5) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a TR SO_2 Group 2 opt-in unit, by the date on which the TR SO_2 Group 2 opt-in unit enters the TR SO_2 Group 2 Trading Program as provided in § 97.741(h).

(c) Reporting data. The owner or operator of a TR SO_2 Group 2 unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for SO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine SO_2 mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter or section 2.4 of appendix D to part 75 of this chapter, as applicable.

(d) Prohibitions. (1) No owner or operator of a TR SO_2 Group 2 unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 97.735.

(2) No owner or operator of a TR SO_2 Group 2 unit shall operate the unit so as to discharge, or allow to be discharged, SO_2 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.

(3) No owner or operator of a TR SO_2 Group 2 unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO_2 mass emissions discharged into the atmosphere or heat input, 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.

(4) No owner or operator of a TR SO_2 Group 2 unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 97.705 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 Administrator 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 designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 97.731(d)(3)(i).

(e) Long-term cold storage. The owner or operator of a TR SO_2 Group 2 unit is subject to the applicable provisions of § 75.4(d) of this chapter concerning units in long-term cold storage.

§ 97.731 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a TR SO_2 Group 2 unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 97.730(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendices B and D to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 97.730(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) [Reserved]

(d) Except as provided in paragraph (a) of this section, the owner or operator of a TR SO_2 Group 2 unit shall comply with the following initial certification and recertification procedures, for a continuous monitoring system (*i.e.,* a continuous emission monitoring system and an excepted monitoring system under appendix D to part 75 of this chapter) under § 97.730(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under § 97.730(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 97.730(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 97.730(a)(1) that may significantly affect the ability of the system to accurately measure or record SO_2 mass emissions or heat input rate or to meet the quality-assurance and quality-control 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 in accordance with § 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 may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: Replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system under § 97.730(a)(1) is subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* For initial certification of a continuous monitoring system under § 97.730(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words "certification" and "initial certification" are replaced by the word "recertification" and the word "certified" is replaced by the word "recertified".

(i) *Notification of certification.* The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with § 97.733.

(ii) *Certification application.* The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the TR SO_2 Group 2 Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, 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 Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) *Certification application approval process.* The Administrator 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 (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that 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 TR SO_2 Group 2 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 Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period specified in paragraph (d)(3) of this section shall not begin before receipt of a complete certification application.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator 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 Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter).

(D) *Audit decertification.* The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 97.732(b).

(v) *Procedures for loss of certification.* If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(1) For a disapproved SO_2 pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of SO_2 and the maximum potential flow rate, as defined in sections 2.1.1.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(2) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(3) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 97.732 Monitoring system out-of-control periods.

(a) *General provisions.* Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or appendix D to 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 monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 97.731 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 Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system 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 for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 97.731 for each disapproved monitoring system.

§ 97.733 Notifications concerning monitoring.

The designated representative of a TR SO_2 Group 2 unit shall submit written notice to the Administrator in accordance with § 75.61 of this chapter.

§ 97.734 Recordkeeping and reporting.

(a) General provisions. The designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements in subparts F and G of part 75 of this chapter, and the requirements of § 97.714(a).

(b) Monitoring plans. The owner or operator of a TR SO_2 Group 2 unit shall comply with requirements of § 75.62 of this chapter.

(c) Certification applications. The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under § 97.731, including the information required under § 75.63 of this chapter.

(d) Quarterly reports. The designated representative shall submit quarterly reports, as follows:

(1) The designated representative shall report the SO_2 mass emissions data and heat input data for the TR SO_2 Group 2 unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering January 1, 2012 through March 31, 2012;

(ii) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.730(b), unless that quarter is the third or fourth quarter of 2011, in which case reporting shall commence in the quarter covering January 1, 2012 through March 31, 2012;

(iii) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved, the calendar quarter corresponding to the date specified in § 97.741(c); and

(iv) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a TR SO_2 Group 2 opt-in unit, the calendar quarter corresponding to the date on which the TR SO_2 Group 1 opt-in unit enters the TR SO_2 Group 2 Trading Program as provided in § 97.71(h).

(2) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.64 of this chapter.

(3) For TR SO_2 Group 2 units that are also subject to the Acid Rain Program, TR NO_X Annual Trading Program, or TR NO_X Ozone Season Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the SO_2 mass emission data, heat input data, and other information required by this subpart.

(4) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(ii) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(2) of this section.

(e) *Compliance certification.* The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) 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:

(1) 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

(2) For a unit with add-on SO_2 emission controls and for all hours where SO_2 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 quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate SO_2 emissions.

§ 97.735 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a TR SO_2 Group 2 unit may submit a petition under § 75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§ 97.730 through 97.734 or paragraph (5)(i) or (ii) of the definition of "owner's share" in § 97.702.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(i) Identification of each unit and source covered by the petition;

(ii) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(iii) A description and diagram of any equipment and procedures used in the proposed alternative;

(iv) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be *de minimis;* and

(v) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

§ 97.740 General requirements for TR SO_2 Group 2 opt-in units.

(a) A TR SO_2 Group 2 opt-in unit must be a unit that:

(1) Is located in a State;

(2) Is not a TR SO_2 Group 2 unit under § 97.704;

(3) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect; and

(4) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of this subpart.

(b) A TR SO_2 Group 2 opt-in unit shall be deemed to be a TR SO_2 Group 2 unit for purposes of applying this subpart, except for §§ 97.705, 97.711, and 97.712.

(c) Solely for purposes of applying the requirements of §§ 97.713 through 97.718 and §§ 97.730 through 97.735, a unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved under § 97.742 shall be deemed to be a TR SO_2 Group 2 unit.

(d) Any TR SO_2 Group 2 opt-in unit, and any unit for which a TR opt-in application is submitted and not withdrawn and is not yet approved or disapproved under § 97.742, located at the same source as one or more TR SO_2 Group 2 units shall have the same designated representative and alternate designated representative as such TR SO_2 Group 2 units.

§ 97.741 Opt-in process.

A unit meeting the requirements for a TR SO_2 Group 2 opt-in unit in § 97.740(a) may become a TR SO_2 Group 2 opt-in unit only if, in accordance with this section, the designated representative of the unit submits a complete TR opt-in application for the unit and the Administrator approves the application.

(a) *Applying to opt-in.* The designated representative of the unit may submit a complete TR opt-in application for the unit at any time, except as provided under § 97.742(e). A complete TR opt-in application shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the unit and the source where the unit is located,

including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, and unit identification number and type;

(2) A certification that the unit:

(i) Is not a TR SO_2 Group 2 unit under § 97.704;

(ii) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(iii) Vents all of its emissions to a stack; and

(iv) Has documented heat input (greater than 0 mmBtu) for more than 876 hours during the 6 months immediately preceding submission of the TR opt-in application;

(3) A monitoring plan in accordance with §§ 97.730 through 97.735;

(4) A statement that the unit, if approved to become a TR SO_2 Group 2 unit under paragraph (g) of this section, may withdraw from the TR SO_2 Group 2 Trading Program only in accordance with § 97.742;

(5) A statement that the unit, if approved to become a TR SO_2 Group 2 unit under paragraph (g) of this section, is subject to, and the owners and operators of the unit must comply with, the requirements of § 97.743;

(6) A complete certificate of representation under § 97.716 consistent with § 97.740, if no designated representative has been previously designated for the source that includes the unit; and

(7) The signature of the designated representative and the date signed.

(b) *Interim review of monitoring plan.* The Administrator will determine, on an interim basis, the sufficiency of the monitoring plan submitted under paragraph (a)(3) of this section. The monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the SO_2 emission rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with §§ 97.730 through 97.735. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(c) *Monitoring and reporting.* (1)(i) If the Administrator determines that the monitoring plan is sufficient under paragraph (b) of this section, the owner or operator of the unit shall monitor and report the SO_2 emission rate and the heat input of the unit and all other applicable parameters, in accordance with §§ 97.730 through 97.735, starting on the date of certification of the necessary monitoring systems under §§ 97.730 through 97.735 and continuing until the TR opt-in application submitted under paragraph (a) of this section is disapproved under this section or, if such TR opt-in application is approved, the date and time when the unit is withdrawn from the TR SO_2 Group 2 Trading Program in accordance with § 97.742.

(ii) The monitoring and reporting under paragraph (c)(1)(i) of this section shall cover the entire control period immediately before the date on which the unit enters the TR SO_2 Group 2 Trading Program under paragraph (h) of this section, during which period monitoring system availability must not be less than 98 percent under §§ 97.730 through 97.735 and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the SO_2 emission rate and the heat input of the unit are monitored and reported in accordance with §§ 97.730 through 97.735 for one or more entire control periods, in addition to the control period under paragraph (c)(1)(ii) of this section, during which control periods monitoring system availability is not less than 98 percent under §§ 97.730 through 97.735 and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the TR SO_2 Group 2 Trading Program under paragraph (h) of this section, such information shall be used as provided in paragraphs (e) and (f) of this section.

(d) *Statement on compliance.* After submitting to the Administrator all quarterly reports required for the unit under paragraph (c) of this section, the designated representative shall submit, in a format prescribed by the Administrator, to the Administrator a statement that, for the years covered by such quarterly reports, the unit was in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(e) *Baseline heat input.* The unit's baseline heat input shall equal:

(1) If the unit's SO_2 emission rate and heat input are monitored and reported for only one entire control period, in accordance with paragraph (c) of this section, the unit's total heat input (in mmBtu) for such control period; or

(2) If the unit's SO_2 emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, the average of the amounts of the unit's total heat input (in mmBtu) for such control periods.

(f) *Baseline SO_2 emission rate.* The unit's baseline SO_2 emission rate shall equal:

(1) If the unit's SO_2 emission rate and heat input are monitored and reported for only one entire control period, in accordance with paragraph (c) of this section, the unit's SO_2 emission rate (in lb/mmBtu) for such control period;

(2) If the unit's SO_2 emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, and the unit does not have add-on SO_2 emission controls during any such control periods, the average of the amounts of the unit's SO_2 emission rate (in lb/mmBtu) for such control periods; or

(3) If the unit's SO_2 emission rate and heat input are monitored and reported for more than one entire control period, in accordance with paragraph (c) of this section, and the unit has add-on SO_2 emission controls during any such control periods, the average of the amounts of the unit's SO_2 emission rate (in lb/mmBtu) for such control periods during which the unit has add-on SO_2 emission controls.

(g) *Review of TR opt-in application.* (1) After the designated representative submits the complete TR opt-in application, quarterly reports, and statement required in paragraphs (a), (c), and (d) of this section and if the Administrator determines that the designated representative shows that the unit meets the requirements for a TR SO_2 Group 2 opt-in unit in § 97.640, the element certified in paragraph (a)(2)(iv) of this section, and the monitoring and reporting requirements of paragraph (c) of this section, the Administrator will issue a written approval of the TR opt-in application for the unit. The written approval will state the unit's baseline heat input and baseline SO_2 emission rate. The Administrator will thereafter establish a compliance account for the source that includes the unit unless the source already has a compliance account.

(2) Notwithstanding paragraphs (a) through (f) of this section, if, at any time before the TR opt-in application is approved under paragraph (g)(1) of this section, the Administrator determines that the unit cannot meet the requirements for a TR SO_2 Group 2 opt-in unit in § 97.740, the element certified in paragraph (a)(2)(iv) of this section, or the monitoring and reporting requirements in paragraph (c) of this section, the Administrator will issue a written disapproval of the TR opt-in application for the unit.

(h) *Date of entry into TR SO_2 Group 2 Trading Program.* A unit for which a

TR opt-in application is approved under paragraph (g)(1) of this section shall become a TR SO_2 Group 2 opt-in unit, and a TR SO_2 Group 2 unit, effective as of the later of January 1, 2012 or January 1 of the first control period during which such approval is issued.

§ 97.742 Withdrawal of TR SO_2 Group 2 opt-in unit from TR SO_2 Group 2 Trading Program.

A TR SO_2 Group 2 opt-in unit may withdraw from the TR SO_2 Group 2 Trading Program only if, in accordance with this section, the designated representative of the unit submits a request to withdraw the unit and the Administrator issues a written approval of the request.

(a) *Requesting withdrawal.* In order to withdraw the TR SO_2 Group 2 opt-in unit from the TR SO_2 Group 2 Trading Program, the designated representative of the unit shall submit to the Administrator a request to withdraw the unit effective as of midnight of December 31 of a specified calendar year, which date must be at least 4 years after December 31 of the year of the unit's entry into the TR SO_2 Group 2 Trading Program under § 97.741(h). The request shall be in a format prescribed by the Administrator and shall be submitted no later than 90 days before the requested effective date of withdrawal.

(b) *Conditions for withdrawal.* Before a TR SO_2 Group 2 opt-in unit covered by the request to withdraw may withdraw from the TR SO_2 Group 2 Trading Program, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the TR SO_2 Group 2 opt-in unit must meet the requirement to hold TR SO_2 Group 2 allowances under §§ 97.724 and 97.725 and cannot have any excess emissions.

(2) After the requirement under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the TR SO_2 Group 2 opt-in unit TR SO_2 Group 2 allowances equal in amount to and allocated for the same or a prior control period as any TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 opt-in unit under § 97.744 for any control period after the date on which the withdrawal is to be effective. If there are no other TR SO_2 Group 2 units at the source, the Administrator will close the compliance account, and the owners and operators of the TR SO_2 Group 2 opt-in unit may submit a TR SO_2 Group 2 allowance transfer for any remaining TR SO_2 Group 2 allowances to another Allowance Management System account in accordance with §§ 97.722 and 97.723.

(c) *Approving withdrawal.* (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of TR SO_2 Group 2 allowances required), the Administrator will issue a written approval of the request to withdraw, which will become effective as of midnight on December 31 of the calendar year for which the withdrawal was requested. The unit covered by the request shall continue to be a TR SO_2 Group 2 opt-in unit until the effective date of the withdrawal and shall comply with all requirements under the TR SO_2 Group 2 Trading Program concerning any control periods for which the unit is a TR SO_2 Group 2 opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the Administrator will issue a written disapproval of the request to withdraw. The unit covered by the request shall continue to be a TR SO_2 Group 2 opt-in unit.

(d) *Reapplication upon failure to meet conditions of withdrawal.* If the Administrator disapproves the request to withdraw, the designated representative of the unit may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(e) *Ability to reapply to the TR SO_2 Group 2 Trading Program.* Once a TR SO_2 Group 2 opt-in unit withdraws from the TR SO_2 Group 2 Trading Program, the designated representative may not submit another opt-in application under § 97.741 for such unit before the date that is 4 years after the date on which the withdrawal became effective.

§ 97.743 Change in regulatory status.

(a) *Notification.* If a TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704, then the designated representative of the unit shall notify the Administrator in writing of such change in the TR SO_2 Group 2 opt-in unit's regulatory status, within 30 days of such change.

(b) *Administrator's actions.* (1) If a TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.604, the Administrator will deduct, from the compliance account of the source that includes the TR SO_2 Group 2 opt-in unit that becomes a TR SO_2 Group 2 unit under § 97.704, TR SO_2 Group 2 allowances equal in amount to and allocated for the same or a prior control period as:

(i) Any TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 opt-in unit under § 97.744 for any control period starting after the date on which the TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704; and

(ii) If the date on which the TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704 is not December 31, the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 opt-in unit under § 97.744 for the control period that includes the date on which the TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704—

(A) Multiplied by the ratio of the number of days, in the control period, starting with the date on which the TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704, divided by the total number of days in the control period, and

(B) Rounded to the nearest allowance.

(2) The designated representative shall ensure that the compliance account of the source that includes the TR SO_2 Group 2 opt-in unit that becomes a TR SO_2 Group 2 unit under § 97.704 contains the TR SO_2 Group 2 allowances necessary for completion of the deduction under paragraph (b)(1) of this section.

(3)(i) For control periods starting after the date on which the TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704, the TR SO_2 Group 2 opt-in unit will be allocated TR SO_2 Group 2 allowances in accordance with § 97.712.

(ii) If the date on which the TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704 is not December 31, the following amount of TR SO_2 Group 2 allowances will be allocated to the TR SO_2 Group 2 opt-in unit (as a TR SO_2 Group 2 unit) in accordance with § 97.712 for the control period that includes the date on which the TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704:

(A) The amount of TR SO_2 Group 2 allowances otherwise allocated to the TR SO_2 Group 2 opt-in unit (as a TR SO_2 Group 2 unit) in accordance with § 97.712 for the control period;

(B) Multiplied by the ratio of the number of days, in the control period, starting with the date on which the TR SO_2 Group 2 opt-in unit becomes a TR SO_2 Group 2 unit under § 97.704, divided by the total number of days in the control period; and

(C) Rounded to the nearest allowance.

§ 97.744 TR SO_2 Group 2 allowance allocations to TR SO_2 Group 2 opt-in units.

(a) *Timing requirements.* (1) When the TR opt-in application is approved for a unit under § 97.741(g), the Administrator will issue TR SO_2 Group 2 allowances and allocate them to the unit for the control period in which the unit enters the TR SO_2 Group 2 Trading Program under § 97.741(h), in accordance with paragraph (b) of this section.

(2) By no later than October 31 of the control period after the control period in which a TR SO_2 Group 2 opt-in unit enters the TR SO_2 Group 2 Trading Program under § 97.741(h) and October 31 of each year thereafter, the Administrator will issue TR SO_2 Group 2 allowances and allocate them to the TR SO_2 Group 2 opt-in unit for the control period that includes such allocation deadline and in which the unit is a TR SO_2 Group 2 opt-in unit, in accordance with paragraph (b) of this section.

(b) *Calculation of allocation.* For each control period for which a TR SO_2 Group 2 opt-in unit is to be allocated TR SO_2 Group 2 allowances, the Administrator will issue and allocate TR SO_2 Group 2 allowances in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the TR SO_2 Group 2 allowance allocation will be the lesser of:

(i) The TR SO_2 Group 2 opt-in unit's baseline heat input determined under § 97.741(g); or

(ii) The TR SO_2 Group 2 opt-in unit's heat input, as determined in accordance with §§ 97.730 through 97.735, for the immediately prior control period, except when the allocation is being calculated for the control period in which the TR SO_2 Group 2 opt-in unit enters the TR SO_2 Group 2 Trading Program under § 97.741(h).

(2) The SO_2 emission rate (in lb/mmBtu) used for calculating TR SO_2 Group 2 allowance allocations will be the lesser of:

(i) The TR SO_2 Group 2 opt-in unit's baseline SO_2 emission rate (in lb/mmBtu) determined under § 97.741(g) and multiplied by 70 percent; or

(ii) The most stringent State or Federal SO_2 emissions limitation applicable to the TR SO_2 Group 2 opt-in unit at any time during the control period for which TR SO_2 Group 2 allowances are to be allocated.

(3) The Administrator will issue TR SO_2 Group 2 allowances and allocate them to the TR SO_2 Group 2 opt-in unit in an amount equaling the heat input under paragraph (b)(1) of this section, multiplied by the SO_2 emission rate under paragraph (b)(2) of this section, divided by 2,000 lb/ton, and rounded to the nearest allowance.

(c) *Recordation.* (1) The Administrator will record, in the compliance account of the source that includes the TR SO_2 Group 2 opt-in unit, the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 opt-in unit under paragraph (a)(1) of this section.

(2) By December 1 of the control period after the control period in which a TR SO_2 Group 2 opt-in unit enters the TR SO_2 Group 2 Trading Program under § 97.741(h) and December 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the TR SO_2 Group 2 opt-in unit, the TR SO_2 Group 2 allowances allocated to the TR SO_2 Group 2 opt-in unit under paragraph (a)(2) of this section.

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