ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 52, 75, 78 and 97

[EPA–HQ–OAR–2021–0668; FRL 8670–01–OAR]

RIN 2060–AV51

Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This action proposes Federal Implementation Plan (FIP) requirements to address twenty-six states' obligations to eliminate significant contribution to nonattainment, or interference with maintenance, of the 2015 ozone National Ambient Air Quality Standard (NAAQS) in other states. The U.S. Environmental Protection Agency (EPA) is proposing this action under the ''good neighbor'' or ''interstate transport'' provision of the Clean Air Act (CAA or Act). The Agency proposes establishing nitrogen oxides emissions budgets requiring fossil fuel-fired power plants in 25 states to participate in an allowance-based ozone season trading program beginning in 2023. The Agency is also proposing to establish nitrogen oxides emissions limitations applicable to certain other industrial stationary sources in 23 states with an earliest possible compliance date of 2026. These industrial source types are: Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; and high-emitting equipment and large boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.

DATES: Comments must be received on or before June 6, 2022.

Public Hearing: The EPA will hold a virtual public hearing on April 21, 2022. Please refer to the **SUPPLEMENTARY INFORMATION** section for additional information on the public hearing.

Information Collection Request (ICR): Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before May 6, 2022.

ADDRESSES: You may send comments, identified by Docket ID No. EPA–HQ–OAR–2021–0668; via the Federal eRulemaking Portal: *https://www.regulations.gov/* (our preferred method). Follow the online instructions for submitting comments.

Instructions: All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to *https://www.regulations.gov/,* including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the ''Public Participation'' heading of the **SUPPLEMENTARY INFORMATION** section of this document. Out of an abundance of caution for members of the public and our staff, the EPA Docket Center and Reading Room are open to the public by appointment only to reduce the risk of transmitting COVID–19. Our Docket Center staff also continues to provide remote customer service via email, phone, and webform. Hand deliveries and couriers may be received by scheduled appointment only. For further information on EPA Docket Center services and the current status, please visit us online at *https://www.epa.gov/dockets.*

The virtual public hearing will be held on April 21, 2022. The virtual public hearing will convene at 10 a.m. Eastern Time (ET) and will conclude at 7 p.m. ET. The EPA may close a session 15 minutes after the last pre-registered speaker has testified if there are no additional speakers. For information or questions about the public hearing, please contact Ms. Holly DeJong at *Dejong.holly@epa.gov.* The EPA will announce further details at *https://www.epa.gov/csapr/csapr-2015-ozone-naaqs.* Refer to the **SUPPLEMENTARY INFORMATION** section for additional information.

FOR FURTHER INFORMATION CONTACT: Ms. Elizabeth Selbst, Air Quality Policy Division, Office of Air Quality Planning and Standards (C539–01), Environmental Protection Agency, 109 TW Alexander Drive, Research Triangle Park, NC 27711; telephone number: (919)-541–3918; email address: *Selbst.elizabeth@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble Glossary of Terms and Abbreviations

The following are abbreviations of terms used in the preamble.

2016v1 2016 Version 1 Emissions Modeling Platform
2016v2 2016 Version 2 Emissions Modeling Platform
4-Step Framework 4-Step Interstate Transport Framework
ACS American Community Survey
AEO Annual Energy Outlook
AQAT Air Quality Assessment Tool
AQMTSD Air Quality Modeling Technical Support Document
BACT Best Available Control Technology
BPT Benefit Per Ton
CAA or Act Clean Air Act
CAIR Clean Air Interstate Rule
CBI Confidential Business Information
CCR Coal Combustion Residual
CDC Centers for Disease Control and Prevention
CEMS Continuous Emissions Monitoring Systems
CES Clean Energy Standards
CHP Combined Heat and Power
CMDB Control Measures Database
CMV Commercial Marine Vehicle
CoST Control Strategy Tool
CPT Cost Per Ton
CSAPR Cross-State Air Pollution Rule
EGU Electric Generating Unit
EIA U.S. Energy Information Agency
EISA Energy Independence and Security Act
ELG Effluent Limitation Guidelines
E.O. Executive Order
EPA or the Agency United States Environmental Protection Agency
FFS Finding of Failure To Submit
FIP Federal Implementation Plan
GIS Geographic Information System
HDGHG Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles
HEDD High Electricity Demand Days
ICI Industrial, Commercial, and Institutional
I/M Inspection and Maintenance
IPM Integrated Planning Model
LNB Low-NO_X Burners
MJO Multi-Jurisdictional Organization
MOVES Motor Vehicle Emission Simulator
MSAT2 Mobile Source Air Toxics Rule
MWC Municipal Waste Combustor
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NEEDS National Electric Energy Data System
NEI National Emissions Inventory
NESHAP National Emissions Standards for Hazardous Air Pollutants
No SISNOSE No Significant Economic Impact on a Substantial Number of Small Entities
Non-EGU Non-Electric Generating Unit
NO_X Nitrogen Oxides
NSPS New Source Performance Standard
NREL National Renewable Energy Lab
NTTAA National Technology Transfer and Advancement Act
OFA Over-Fire Air
OMB United States Office of Management and Budget
OSAT/APCA Ozone Source Apportionment Technology/Anthropogenic Precursor Culpability Analysis
OTC Ozone Transport Commission
OTR Ozone Transport Region
OTSA Oklahoma Tribal Statistical Area
PEMS Predictive Emissions Monitoring Systems

$PM_{2.5}$ Fine Particulate Matter
ppb parts per billion
ppm parts per million
ppmvd parts per million by volume, dry
PRA Paperwork Reduction Act
RACT Reasonably Available Control Technology
RFA Regulatory Flexibility Act
RICE Reciprocating Internal Combustion Engines
ROP Rate of Progress
RPS Renewable Portfolio Standards
RRF Relative Response Factor
SAFE Safer Affordable Fuel-Efficient Vehicles Rule
SAFETEA Safe, Accountable, Flexible, Efficient, Transportation Equity Act
SCR Selective Catalytic Reduction
SIP State Implementation Plan
SMOKE Sparse Matrix Operator Kernel Emissions
SNCR Selective Non-Catalytic Reduction
SO_2 Sulfur Dioxide
tpd ton per day
TSD Technical Support Document
UMRA Unfunded Mandates Reform Act
VMT Vehicle Miles Traveled
VOCs Volatile Organic Compounds
WRAP Western Regional Air Partnership
WRF Weather Research and Forecasting

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I. Executive Summary

This proposed rule would resolve the interstate transport obligations of 26 states under CAA section 110(a)(2)(D)(i)(I), referred to as the ''good neighbor provision'' or the ''interstate transport provision'' of the Act, for the 2015 ozone NAAQS. On October 1, 2015, the EPA revised the primary and secondary 8-hour standards for ozone to 70 parts per billion (ppb).[1] States were required to provide ozone infrastructure State Implementation Plan (SIP) submissions to fulfill interstate transport obligations for the 2015 ozone NAAQS by October 1, 2018.

The EPA proposes to make a finding that interstate transport of ozone precursor emissions from 26 upwind states (Alabama, Arkansas, California, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming) is significantly contributing to downwind nonattainment or interfering with maintenance of the 2015 ozone NAAQS in other states, based on projected nitrogen oxides (NO_X) emissions in the 2023 ozone season. The EPA is proposing to issue FIP requirements to eliminate interstate transport of ozone precursors from these 26 states that significantly contributes to nonattainment or interferes with maintenance of the NAAQS in other states.

The EPA is proposing FIPs for 23 states for which the Agency has not approved an ozone transport SIP that was submitted for the 2015 ozone NAAQS: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Tennessee, Texas, Utah, West Virginia, Wisconsin, and Wyoming. In this proposed rule, the EPA is proposing to issue FIPs for two states—Pennsylvania and Virginia—for which the EPA issued a Finding of Failure to Submit for 2015 ozone transport SIPs with an effective date of January 6, 2020. Under CAA section 301(d)(4), the EPA proposes to extend FIP requirements to apply in Indian country located within the upwind geography of the proposed rule, including Indian reservation lands and other areas of Indian country over which the EPA or a tribe has demonstrated that a tribe has jurisdiction.[2] The EPA is also proposing a FIP for Delaware and an error correction for the Agency's May 1, 2020, approval at 85 FR 25307 of the interstate transport elements for Delaware's October 11, 2018, and December 26, 2019, ozone infrastructure SIP submissions.

In this proposed rule, the EPA proposes to establish new ozone season NO_X emissions budgets beginning in 2023 for Electric Generating Unit (EGU) sources. The EPA is also proposing to establish emissions limitations beginning in 2026 for certain other industrial stationary sources (referred to generally as ''non-Electric Generating Units'' (non-EGUs)). Taken together, these strategies will fully eliminate the covered states' significant contribution to downwind ozone air quality problems in other states.

The EPA proposes to implement the necessary emissions reductions as follows. The proposed FIP requirements establish ozone season NO_X emissions budgets for EGUs in 25 states (Alabama, Arkansas, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming) and require EGUs in these states to participate in a revised version of the Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 3 Trading Program that was previously established in the Revised CSAPR Update.[3] The EPA proposes to amend existing FIPs for 12 states currently participating in the CSAPR NO_X Ozone Season Group 3 Trading Program (Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia) to replace their existing emissions budgets established in the Revised CSAPR Update (with respect to the 2008 ozone NAAQS) with new

[1] *See* 80 FR 65291 (October 26, 2015).

[2] In general, specific tribal names or reservations are not identified separately in this proposal except as needed. See Section IV.C.2 of this notice for further discussion.

[3] As explained in Section VI.C.1 of this notice, EPA proposes finding that EGU sources within the State of California are sufficiently controlled such that no further emissions reductions are needed from them to eliminate significant contribution to downwind states.

emissions budgets. For eight states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program under SIPs or FIPs, the EPA is proposing to issue new FIPs for two states (Alabama and Missouri) and amend existing FIPs for six states (Arkansas, Mississippi, Oklahoma, Tennessee, Texas, and Wisconsin) to transition EGU sources in these states from the Group 2 program to the revised Group 3 trading program, beginning with the 2023 ozone season. EPA proposes to issue new FIPs for five states not currently covered by any CSAPR NO_X ozone season trading program: Delaware, Minnesota, Nevada, Utah, and Wyoming.

Under this proposed rulemaking, emissions reductions in the selected control stringency would be achieved as soon as they are available, some of which are scheduled to occur by the 2023 ozone season and prior to the August 3, 2024, attainment date for areas classified as Moderate nonattainment for the 2015 ozone NAAQS, and the rest of which occur as soon as possible thereafter through the 2026 ozone season, prior to the August 3, 2027, attainment date for areas classified as Serious nonattainment for the 2015 ozone NAAQS. As discussed in Section VII.A.2 of this notice, the EPA proposes to find that the 2026 ozone season is as expeditious as practicable to implement substantial emissions reductions from potential new post-combustion control installations at EGUs as well as from installation of new pollution controls at non-EGUs.

These EGU emissions reductions are scheduled to begin in the 2026 ozone season based on the feasibility of control installation for EGUs in 22 states that remain linked to downwind nonattainment and maintenance receptors in that year. These 22 states are: Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming. The additional emissions reductions required for these states are based primarily on the potential retrofit of additional post-combustion controls for NO_X on most coal steam EGUs and a portion of oil/gas steam EGUs that are currently lacking such controls.

In this proposed rule, the EPA introduces additional features to the allowance-based trading program approach for EGUs, including dynamic adjustments of the emissions budgets over time and backstop daily emissions rate limits for most coal-fired units, that will help maintain control stringency over time and improve emissions performance at individual units, providing further assurance that existing pollution controls will be operated during the ozone season and that the emission reductions necessary to meet good neighbor requirements will be achieved.

The EPA proposes to find that NO_X emissions from non-EGU sources are significantly contributing to nonattainment or interfering with maintenance of the 2015 ozone NAAQS and that cost-effective controls for NO_X emissions reductions are available in certain industrial source categories that would result in meaningful air quality improvements in downwind receptors. The EPA proposes to require emissions limitations beginning in 2026 for non-EGUs located within 23 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming. The proposed rule establishes NO_X emissions limitations during the ozone season for the following unit types for sources in non-EGU industries: Reciprocating internal combustion in Pipeline Transportation of Natural Gas sources; kilns in Cement and Cement Product Manufacturing sources; boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing sources; furnaces in Glass and Glass Product Manufacturing sources; and high-emitting equipment and large boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.

A. Purpose of the Regulatory Action

The purpose of this rulemaking is to protect public health and the environment by reducing interstate transport of certain air pollutants that significantly contribute to nonattainment, or interfere with maintenance, of the 2015 ozone NAAQS in other states. Ground-level ozone has detrimental effects on human health as well as vegetation and ecosystems. Acute and chronic exposure to ozone in humans is associated with premature mortality and a number of morbidity effects, such as asthma exacerbation. Ozone exposure can also negatively impact ecosystems by limiting tree growth, causing foliar injury, and changing ecosystem community composition. Section IV of this proposed rule provides additional evidence of the harmful effects of ozone exposure on human health and the environment. Studies have established that ozone air pollution can be transported over hundreds of miles, with elevated ground-level ozone concentrations occurring in rural and metropolitan areas.[4] [5] Assessments of ozone control approaches have concluded that control strategies targeting reduction of NO_X emissions are an effective method to reduce regional-scale ozone transport.[6]

CAA section 110(a)(2)(D)(i)(I) requires states to prohibit emissions that will contribute significantly to nonattainment or interfere with maintenance in any other state with respect to any primary or secondary NAAQS.[7] States fulfill their primary responsibility to address interstate transport emissions under the good neighbor provision by submitting SIPs containing enforceable emission limitations and other control measures, means, or techniques required to address the interstate transport provision. Within 3 years of the EPA promulgating a new or revised NAAQS, states are required to provide infrastructure SIP submittals, including good neighbor SIPs. *See* CAA section 110(a)(1) and (2). When states do not submit approvable interstate transport SIPs or fail to submit interstate transport SIPs by the statutory deadline, the CAA requires the EPA to issue FIPs to ensure that states eliminate their significant contribution to downwind air quality problems under the good neighbor provision. *See generally* CAA section 110(k) and 110(c). As such, in this proposed rule, the EPA is proposing requirements to fully address good neighbor obligations for these states for the 2015 ozone NAAQS under its authority to promulgate FIPs under CAA section 110(c).

It is appropriate to issue this proposal at this time for at least three reasons. First, this proposal will ensure that necessary emissions reductions to eliminate significant contribution are achieved as expeditiously as practicable. The EPA's anticipated timing will provide for all possible emissions reductions to go into effect

[4] Bergin, M.S. et al. (2007) Regional air quality: Local and interstate impacts of NO_X and SO_2 emissions on ozone and fine particulate matter in the eastern United States. Environmental Sci & Tech. 41: 4677–4689.

[5] Liao, K. et al. (2013) Impacts of interstate transport of pollutants on high ozone events over the Mid-Atlantic United States. Atmospheric Environment 84, 100–112.

[6] *See* 82 FR 51238, 51248 (November 3, 2017) [citing 76 FR 48208, 48222 (August 8, 2011)] and 63 FR 57381 (October 27, 1998).

[7] 42 U.S.C. 7410(a)(2)(D)(i)(I).

beginning in the 2023 ozone season, which is aligned with the next upcoming attainment date of August 3, 2024, for areas classified as Moderate nonattainment under the 2015 ozone standard. Additional emissions reductions that the EPA finds not possible to implement by that attainment date are proposed to take effect as expeditiously as practicable, with the full suite of emissions reductions taking effect by the 2026 ozone season, which is aligned with the August 3, 2027, attainment date for areas classified as Serious nonattainment under the 2015 ozone NAAQS. As explained in sections V.A, VI, and VII.A of this proposed rule, these proposed timeframes for eliminating significant contribution are consistent with the provisions of title I of the CAA. Second, this proposal will provide states with as much information as the EPA can supply at this time to support their ability to submit SIP revisions to achieve the emissions reductions the EPA believes necessary to eliminate significant contribution. Third, for all of the states included in this proposed rule, the EPA's modeling and analysis indicate that additional emissions reductions beyond those which are provided in any state's 2015 ozone transport SIP are necessary to eliminate significant contribution.

The EPA anticipates that the states covered in this proposed FIP rulemaking may not have adequate provisions in their SIPs to address their interstate transport obligations for the 2015 ozone NAAQS. As discussed in Section IV.B.2 of this proposed rule, the EPA has, for certain states, made findings that the state failed to submit a complete good neighbor SIP revision for the 2015 ozone NAAQS. For certain other states, the EPA has proposed, but has not finalized, actions disapproving good neighbor SIP revisions. And for other states, the EPA has not yet proposed action on their good neighbor SIP submittals, but these submittals are currently under review, and EPA intends to act on these submittals in the coming months. The EPA will not finalize this proposed FIP action for any state for which it has not taken final action either disapproving that state's good neighbor SIP submittal or finding that the state failed to submit a complete SIP.

The EPA conducted air quality modeling for future analytic years to identify (1) the downwind areas that are expected to have trouble attaining or maintaining the 2015 ozone NAAQS in the future and (2) the contribution of ozone transport from upwind states to the downwind air quality problems. Section V of this proposed rule provides a full description of the results of EPA's air quality modeling and relevant analyses for the proposed rulemaking. Based on EPA's air quality analysis, a total of 27 upwind states are linked above the 1 percent of the NAAQS threshold to downwind air quality problems in other states. The EPA had previously approved 2015 ozone transport SIPs submitted by two of these states—Oregon and Delaware—and proposes in this proposed rule to issue an error correction for its prior approval of Delaware's 2015 ozone transport SIP (*see* Section IV.C.1 of this notice for additional information on the proposed error correction). The EPA is not proposing any change to its prior approval of Oregon's 2015 ozone transport SIP, a determination which is further described in Section V.F of this proposed rule.

In this proposed rule, the EPA is proposing to issue FIP requirements for 26 states, which include emissions reductions for EGU sources within the borders of 25 states (described in Section VII.B of this proposed rule) and include emissions reductions for non-EGU sources within the borders of 23 states (described in Section VII.C in this proposed rule). Based on EPA's assessment of remaining air quality issues and additional emissions control strategies, the EPA further proposes to find that the EGU and non-EGU NO_X emissions reductions required in the proposed rule would fully eliminate these states' significant contributions to downwind air quality problems for the 2015 ozone NAAQS. By eliminating significant contribution from these upwind states, this rule, if finalized as proposed, will make substantial and meaningful improvements in air quality by reducing ozone levels at the identified downwind receptors as well as many other areas of the country.

1. Emissions Limitations for EGUs Established by the Proposed Rule

In this proposed rule, the EPA proposes to issue FIP requirements that include new NO_X ozone season emissions budgets for EGU sources within the borders of the 25 states listed in Table I.A–1, with implementation of these emissions budgets beginning in the 2023 ozone season. The EPA proposes to find that these emissions reductions are necessary to address upwind states' interstate transport obligations for the 2015 ozone NAAQS.

TABLE I.A–1—PROPOSED LIST OF 25 COVERED STATES FOR EGU EMISSIONS REDUCTIONS FOR THE 2015 8-HOUR OZONE NAAQS

State
Alabama
Arkansas
Delaware
Illinois
Indiana
Kentucky
Louisiana
Maryland
Michigan
Minnesota
Mississippi
Missouri
Nevada
New Jersey
New York
Ohio
Oklahoma
Pennsylvania
Tennessee
Texas
Utah
Virginia
West Virginia
Wisconsin
Wyoming

The EPA proposes to expand the CSAPR NO_X Ozone Season Group 3 Trading Program beginning in the 2023 ozone season. Specifically, the FIPs would require power plants within the borders of the 25 states listed in Table I.A–1 to participate in a revised version of the CSAPR NO_X Ozone Season Group 3 Trading Program created by the Revised CSAPR Update. Affected EGUs within the borders of twelve states currently participating in the Group 3 Trading Program under FIPs or SIPs would remain in the program, with revised provisions beginning in the 2023 ozone season, under this proposed rule: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. The FIPs would also require affected EGUs within the borders of eight states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program (the ''Group 2 trading program'') under existing FIPs or existing SIPs to transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 control period: (Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin).[8] Finally, the EPA is

[8] Six of these eight states (Arkansas, Mississippi, Oklahoma, Tennessee, Texas, and Wisconsin) currently participate in the federal Group 2 trading program pursuant to the FIPs finalized in the CSAPR Update, so the FIPs proposed in this rulemaking would amend the existing FIPs for these

proposing to issue new FIPs for EGUs within the borders of five states not currently covered by any CSAPR trading program for seasonal NO_X emissions: Delaware, Minnesota, Nevada, Utah, and Wyoming. If the proposed FIP is finalized, sources in these states would enter the Group 3 trading program in the 2023 control period following the effective date of the final rule.[9] In all cases, if the state submits and the EPA approves a SIP revision that would fully achieve the emissions reductions needed to meet the state's good neighbor obligations with respect to the 2015 ozone NAAQS before a final rule is promulgated in this rulemaking, the proposed FIP requirements summarized above would not be finalized. Refer to Section VII.B of this proposed rule for details on EGU regulatory requirements.

2. Emissions Limitations for Non-EGU Stationary Point Sources Established by the Proposed Rule

In this proposed rule, the EPA proposes to issue FIP requirements that include new NO_X emissions limitations for non-Electric Generating Unit (non-EGU) sources in 23 states, with earliest possible compliance dates for these emissions limitations beginning in 2026. The EPA proposes to require emissions reductions from non-EGU sources to address interstate transport obligations for the 2015 ozone NAAQS for the 23 states listed in Table I.A–2.

TABLE I.A–2—PROPOSED LIST OF 23 COVERED STATES FOR NON-EGU EMISSIONS REDUCTIONS FOR THE 2015 8-HOUR OZONE NAAQS

State
Arkansas
California
Illinois
Indiana
Kentucky
Louisiana
Maryland
Michigan
Minnesota
Mississippi
Missouri
Nevada
New Jersey
New York
Ohio
Oklahoma
Pennsylvania
Texas
Utah
Virginia
West Virginia
Wisconsin
Wyoming

The EPA is proposing to require emissions limitations for the following unit types in non-EGU industries: Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas sources; kilns in Cement and Cement Product Manufacturing sources; boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing sources; furnaces in Glass and Glass Product Manufacturing sources; and high-emitting equipment and large boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills. Refer to Table III.A–1 for a list of North American Industry Classification System (NAICS) codes for each entity included for regulation under this proposed rule.

3. Proposed Error Correction for Previously Approved 2015 Ozone Transport SIP

The EPA proposes to make an error correction under CAA section 110(k)(6) of its May 1, 2020, approval at 85 FR 25307 of the interstate transport elements for Delaware's October 11, 2018, and December 26, 2019, ozone infrastructure SIP submissions as satisfying the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS. The EPA proposes to determine that the basis for the prior SIP approval is invalidated by the Agency's more recent technical evaluation of air quality modeling performed in support of the proposed rule,[10] and that Delaware has unresolved interstate transport obligations for the 2015 ozone NAAQS. In this proposed rule, the EPA is also exercising its authority to propose to issue a FIP for Delaware in light of these unresolved interstate transport obligations.

4. Request for Comment on All Aspects of the Proposal

Throughout this proposed rule, unless noted otherwise, the EPA is requesting comments on all aspects of the proposal to enable the Agency to develop a final rule that, consistent with our responsibilities under section 110 of the CAA, eliminates air pollution that significantly contributes to nonattainment or interference with maintenance of the 2015 ozone NAAQS. This proposed rule adheres closely to the legal and analytical framework that the EPA has applied in the past in implementing the good neighbor provision of the CAA, as well as the ample case law reviewing that framework. At the same time, in this proposal, the EPA is applying lessons learned from the performance of regulatory programs established by previous ozone transport rulemakings, as well as updating the Agency's application of the 4-step interstate transport framework with recent information on the nature of ozone transport and emissions reductions opportunities in order to eliminate significant contribution for the more stringent 2015 ozone NAAQS under the good neighbor provision. The EPA invites comments and information to support its efforts to improve the regulation of interstate ozone transport under the good neighbor provision and to fulfill our mission to protect human health and the environment. The EPA will carefully consider information provided in response to this request and will respond to comments submitted through the regulatory docket in the final rule.

B. Summary of the Major Provisions of the Regulatory Action

The EPA is applying the 4-step interstate transport framework developed in CSAPR, the CSAPR Update, the Revised CSAPR Update, and other previous ozone transport rules to propose to further limit NO_X emissions from EGU sources within the borders of 25 states during the ozone season (May 1 through September 30) and to limit ozone season NO_X emissions from non-EGU sources in 23 states to reduce interstate ozone transport under the authority provided in CAA section 110(a)(2)(D)(i)(I). The 4-step interstate transport framework provides a stepwise method for the EPA to propose rule provisions that are required to address the requirements of the good neighbor provision for the 2015 ozone NAAQS: (1) Identifying downwind receptors that are expected to have problems attaining or

states. The other two states (Alabama and Missouri) have already replaced the FIPs finalized in the CSAPR Update with approved SIP revisions that require their EGUs to participate in state Group 2 trading programs integrated with the federal Group 2 trading program, so the FIPs proposed in this action would constitute new FIPs for these states, and the EPA would cease implementation of the state Group 2 trading programs included in the two states' SIPs.

[9] Two states, Kansas and Iowa, will remain in the Group 2 Trading Program.

[10] *See* the Air Quality Modeling Technical Support Document (AQM TSD) in the docket for this proposed rule.

maintaining the NAAQS; (2) determining which upwind states contribute to these identified problems in amounts sufficient to ''link'' them to the downwind air quality problems (*i.e.,* in this proposed rule, a contribution threshold of 1 percent of the NAAQS); (3) for states linked to downwind air quality problems, identifying upwind emissions that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS; and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind areas, implementing the necessary emissions reductions through enforceable measures. In this proposed rule, the EPA applies the 4-step framework to evaluate upwind states' obligations to reduce interstate transport of ozone precursor emissions for the 2015 ozone NAAQS. The remainder of this section provides a general overview of the EPA's application of the 4-step framework as it applies to major provisions of the proposed rule; additional details regarding EPA's proposed rule approach are found in Section IV of this proposed rule.

In order to apply the first step of the 4-step framework to the 2015 ozone NAAQS, the EPA performed air quality modeling to project ozone concentrations at air quality monitoring sites in 2023, 2026, and 2032.[11] The EPA evaluated projected ozone concentrations for the 2023 analytic year at individual monitoring sites and considered current ozone monitoring data at these sites to identify receptors that are anticipated to have problems attaining or maintaining the 2015 ozone NAAQS. This analysis was then repeated using projected ozone concentrations for 2026 and 2032.

To apply the second step of the framework, the EPA used air quality modeling to quantify the contributions from upwind states to ozone concentrations in 2023 and 2026 at downwind receptors.[12] Once quantified, EPA then evaluated these contributions relative to a screening threshold of 1 percent of the NAAQS (*i.e.,* 0.70 ppb).[13] States with contributions that equaled or exceeded 1 percent of the NAAQS were identified as warranting further analysis at Step 3 of the four-step framework to determine if the upwind state significantly contributes to nonattainment or interference with maintenance in a downwind state. States with contributions below 1 percent of the NAAQS were considered not to significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind states. Based on EPA's most recent air quality modeling and contribution analysis using 2023 as the analytic year, the EPA proposes to find that the following 27 states have contributions that equal or exceed 1 percent of the 2015 ozone NAAQS, and, thereby, warrant further analysis of significant contribution to nonattainment or interference with maintenance of the NAAQS: Alabama, Arkansas, California, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming. Further evaluation of the locations in California to which Oregon was linked at Step 2 leads the EPA to conclude downwind areas represented by these monitoring sites should not be considered interstate ozone transport receptors. Therefore, the EPA is not proposing any further emissions reductions from the state of Oregon because there is no significant contribution required to be eliminated under the interstate transport provision, as described in Section V.F of this proposed rule.

Based on the air quality analysis presented in Section V of this proposed rule, the EPA proposes to find that in the absence of additional emissions reductions in those states the majority of the states that the EPA is proposing to participate in the Ozone Season Group 3 Trading Program will continue to contribute above the 1 percent of the NAAQS threshold to at least one receptor whose nonattainment and maintenance concerns persist through the 2026 ozone season, with the exception of Alabama, Delaware, and Tennessee. As a result, EPA's evaluation of emissions reduction potential at Step 3 for Alabama, Delaware, and Tennessee is limited to emission reductions achievable by the 2023 ozone season. For each of these three states, EPA's analysis does not consider, nor does the EPA propose to require, emissions reductions at either EGUs or non-EGUs that cannot be implemented until the 2026 ozone season.

At the third step of the 4-step framework, EPA applied a multi-factor test that incorporates cost, availability of emissions reductions, and air quality impacts at the downwind receptors to determine the amount of ozone precursor emissions from the linked upwind states that ''significantly'' contribute to downwind nonattainment or maintenance receptors. In this proposed rule, the EPA proposes to apply the multifactor test described in Section VI.A of this proposed rule to both EGU and non-EGU sources. The EPA assessed the potential emissions reductions in 2023 and 2026, as well as in intervening and later years to determine the emissions reductions required to eliminate significant contribution in any future year where downwind areas are projected to have potential problems attaining or maintaining the 2015 ozone NAAQS.

For EGU sources, the EPA evaluated the following set of widely-available NO_X emissions control technologies: (1) Fully operating existing selective catalytic reduction (SCR) controls, including both optimizing NO_X removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art NO_X combustion controls; (3) fully operating existing selective non-catalytic reduction (SNCR) controls, including both optimizing NO_X removal by existing operational SNCRs and turning on and optimizing existing idled SNCRs; (4) installing new SNCRs; (5) installing new SCRs; and (6) generation shifting. For the reasons explained in Section VI of this proposed rule and supported by the EGU NO_X Mitigation Strategies Proposed Rule Technical Support Document (TSD) included in the docket for this proposed rule, the EPA determined that for the regional, multi-state scale of this rulemaking, only fully operating and optimizing existing SCRs and existing SNCRs (EGU NO_X emissions controls options 1 and 3 in the list earlier) are possible for the 2023 ozone season. The EPA determined that state-of-the-art NO_X combustion controls at EGUs (emissions control option 2 in the list above) are available by the beginning of the 2024 ozone season. Based on EPA's assessment of the earliest possible timeframe for installation of new SNCR and SCRs (EGU emissions controls options 4 and 5 in the list), the EPA proposes to require emissions reductions commensurate with these controls by the beginning of the 2026 ozone season. *See* Section VI.B.1 of this proposed rule for a full description of

[11] These 3 analytic years are the last full ozone seasons before, and thus align with, upcoming attainment dates for the 2015 ozone NAAQS: August 3, 2024, for areas classified as Moderate nonattainment, August 3, 2027, for areas classified as Serious nonattainment, and August 3, 2033, for areas classified as Severe. *See* 83 FR 25776.

[12] The EPA did not perform contribution modeling for 2032 since contribution data for this year were not needed to identify upwind states to be analyzed in Step 3.

[13] *See* Section V of this proposed rule for explanation of EPA's use of the 1 percent of the NAAQS threshold in the Step 2 analysis.

EPA's analysis of NO_X emissions mitigation strategies for EGU sources.

The EPA proposes control stringency levels that maximize incremental NO_X emissions reduction potential from EGUs and corresponding downwind ozone air quality improvements to the extent feasible in each year analyzed. The EPA believes that the required controls provide cost-effective reductions of NO_X emissions that will provide substantial improvements in downwind ozone air quality to address interstate transport obligations for the 2015 ozone NAAQS in a timely manner. These controls represent greater stringency in upwind EGU controls than in EPA's most recent ozone transport rulemakings, such as the CSAPR Update and the Revised CSAPR Update. However, programs to address interstate ozone transport based on the retrofit of post-combustion controls are by no means unprecedented. In prior ozone transport rulemakings such as the NO_X SIP Call and the Clean Air Interstate Rule (CAIR), the EPA established EGU budgets premised on the widespread availability of retrofitting EGUs with post-combustion emissions controls such as SCR.[14] While these programs successfully drove many EGUs to retrofit post-combustion controls, other EGUs throughout the present geography of linked upwind states continue to operate without such controls and continue to emit at relatively high rates more than 20 years after similar units reduced these emissions under prior interstate ozone transport rulemakings.

Furthermore, the CSAPR Update provided only a partial remedy for eliminating significant contribution for the 2008 ozone NAAQS, as needed to obtain available reductions by the 2017 ozone season. In that rule, the EPA made no determination regarding the appropriateness of more stringent EGU NO_X controls that would be required for a *full* remedy for interstate transport for the 2008 ozone NAAQS. Following the remand of the CSAPR Update in *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019) (*Wisconsin*), the EPA again declined to require the retrofit of new post-combustion controls on EGUs in the Revised CSAPR Update, but that determination was based on a specific timing consideration: Downwind air quality problems under the 2008 ozone NAAQS were projected to resolve before post-combustion control retrofits could be accomplished on a fleetwide, regional scale. *See* 86 FR 23054, 23110 (April 30, 2021).

In this proposed rulemaking, the EPA is addressing good neighbor obligations for the more stringent 2015 ozone NAAQS, and the Agency observes ongoing and persistent contribution from upwind states to ozone nonattainment and maintenance receptors in other states under that NAAQS. As further discussed in Section VI of this proposed rule, the nature of this contribution warrants a greater degree of control stringency than the EPA determined to be necessary to eliminate significant contribution of ozone transport in prior CSAPR rulemakings. The EPA is therefore returning to EGU NO_X control strategies commensurate with those determined to be necessary in the NO_X SIP Call and CAIR.

Based on the Step 3 analysis described in Section VI of this proposed rule, the EPA is proposing that emissions reductions commensurate with the full operation of all existing post-combustion controls (both SCRs and SNCRs) and state-of-the-art combustion control upgrades constitute the Agency's selected control stringency for EGUs within the borders of 25 states linked to downwind nonattainment or maintenance in 2023 (Alabama, Arkansas, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming). For 22 of those states that are also linked in 2026 (Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming), the EPA is determining that the selected EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal steam units of 100 MW or greater capacity (excepting circulating fluidized bed units (CFB)), new SNCR on coal steam units of less than 100 MW capacity and CFBs, and SCR on oil/gas steam units greater than 100 MW that have historically emitted at least 150 tons of NO_X per ozone season.

To identify appropriate control strategies for non-EGU sources to achieve NO_X emissions reductions that would result in meaningful air quality improvements in downwind areas, the EPA developed an analytical framework to evaluate the air quality impacts of potential emissions reductions from non-EGU sources located in the linked upwind states. The EPA incorporated air quality modeling information, annual emissions, and information about potential controls to determine which industries, if subject to further control requirements, would have the greatest impact in providing air quality improvements at the downwind receptors. This evaluation was subject to a marginal cost threshold of up to $7,500 per ton, which the EPA determined based on information available to the Agency about existing control device efficiency and cost information. Additional information on the analytical framework is described in Section VI.B.2 of this proposed rule and is presented in the memorandum titled *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* (''Non-EGU Screening Assessment memorandum''), which is available in the docket for this proposed rulemaking. Based on the results of this assessment, the EPA identified emissions unit types in seven industries (identified in Section I.A.2 of this proposed rule) that provide opportunities for NO_X emissions reductions that result in meaningful impacts on air quality at the downwind receptors.

The EPA performed air quality analysis using the Ozone Air Quality Assessment Tool (AQAT) to determine whether the proposed emissions reductions for both EGUs and non-EGUs potentially create an ''over-control'' scenario whereby (1) the expected ozone improvements would be greater than necessary to resolve the downwind ozone pollution problem (*i.e.,* beyond what is necessary to resolve all nonattainment and maintenance problems to which an upwind state is linked) or (2) the expected ozone improvements would reduce the upwind state's ozone contributions below the screening threshold (*i.e.,* 1 percent of the NAAQS or 0.70 ppb). The EPA's over-control analysis, discussed in Section VI.D.4 of this proposed rule, shows that the proposed control stringencies for EGU and non-EGU sources do not over-control upwind states' emissions either with respect to the downwind air quality problems to which they are linked or with respect to the 1 percent of the NAAQS contribution threshold, such that over-control would trigger re-evaluation at Step 3 for any linked upwind state.

[14] *See, e.g.,* 70 FR 25162, 25205–06 (May 12, 2005).

Based on the multi-factor test applied to both EGU and non-EGU sources and our subsequent assessment of over-control, the EPA finds that the selected EGU and non-EGU control stringencies constitute the elimination of significant contribution and interference with maintenance, without over-controlling emissions, from the 26 upwind states subject to EGU and non-EGU emissions reductions requirements under the proposed rule. In order to eliminate significant contribution and interference with maintenance through the fourth step of the 4-step framework, as described in Section VII of this proposed rule, the EPA is establishing emissions budgets for EGUs within the borders of 25 states that reflect the remaining allowable emissions after the emissions reductions associated with the selected control stringency have been achieved. For the same reason, the EPA is establishing non-EGU emissions limits in 23 states that result in the elimination of significant contribution from non-EGU sources in these states. For additional details about the test and the over-control analysis, *see* the document titled, ''Ozone Transport Policy Analysis Proposed Rule TSD'' included in the docket for this rulemaking.

In this fourth step of the 4-step framework, the EPA proposes to include enforceable measures in the promulgated FIPs to achieve the required emissions reductions in each of the 26 states. Specifically, the FIPs would require covered power plants within the borders of the 25 states listed in Table I.A–1 to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program created by the Revised CSAPR Update. Affected EGUs within the borders of twelve states currently participating in the Group 3 Trading Program would remain in the program, with revised provisions beginning in the 2023 ozone season, under this proposed rule: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. Affected EGUs within the borders of eight states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program (the ''Group 2 trading program'')—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin—would transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 control period,[15] and affected EGUs within the borders of five states not currently covered by any CSAPR trading program for seasonal NO_X emissions—Delaware, Minnesota, Nevada, Utah, and Wyoming—would enter the Group 3 trading program in the 2023 control period following the effective date of the final rule. In addition, the EPA proposes to revise other aspects of the Group 3 trading program to help maintain control stringency over time and improve emissions performance at individual units, offering a necessary measure of assurance that existing pollution controls will be operated during the ozone season, as described in Section VII of this proposed rule. This proposal does not revise the budget stringency and geography of the existing CSAPR NO_X Ozone Season Group 1 trading program. Aside from the eight states moving from the Group 2 trading program to the Group 3 trading program under the proposed rule, this proposal otherwise leaves unchanged the budget stringency of the existing CSAPR NO_X Ozone Season Group 2 trading program.

The EPA is proposing preset ozone season NO_X emissions budgets for the 2023 and 2024 ozone seasons, as explained in Section VII.B of this proposed rule and as shown in Table I.B–1.

TABLE I.B–1—PROPOSED AND ILLUSTRATIVE CSAPR NO_X OZONE SEASON GROUP 3 STATE EMISSIONS BUDGETS FOR 2023 THROUGH 2026 CONTROL PERIODS *

State	Proposed emissions budgets for 2023 control period (tons)	Proposed emissions budgets for 2024 control period (tons)	Illustrative emissions budgets for 2025 control period (tons)	Illustrative emissions budgets for 2026 control period (tons)
Alabama	6,364	6,306	6,306	6,306
Arkansas	8,889	8,889	8,889	3,923
Delaware	384	434	434	434
Illinois	7,364	7,463	7,463	6,115
Indiana	11,151	9,391	8,714	7,791
Kentucky	11,640	11,640	11,134	7,573
Louisiana	9,312	9,312	9,179	3,752
Maryland	1,187	1,187	1,187	1,189
Michigan	10,718	10,718	10,759	6,114
Minnesota	3,921	3,921	3,910	2,536
Mississippi	5,024	4,400	4,400	1,914
Missouri	11,857	11,857	10,456	7,246
Nevada	2,280	2,372	2,372	1,211
New Jersey	799	799	799	799
New York	3,763	3,763	3,763	3,238
Ohio	8,369	8,369	8,369	8,586
Oklahoma	10,265	9,573	9,393	4,275
Pennsylvania	8,855	8,855	8,855	6,819
Tennessee	4,234	4,234	4,008	4,008
Texas	38,284	38,284	36,619	21,946
Utah	14,981	15,146	15,146	2,620
Virginia	3,090	2,814	2,948	2,567
West Virginia	12,478	12,478	12,478	10,597
Wisconsin	5,963	5,057	4,198	3,473

[15] The EPA would deem participation in the Group 3 trading program by the EGUs in these eight states as also addressing the respective states' good neighbor obligations with respect to the 2008 ozone NAAQS (for all eight states), the 1997 ozone NAAQS (for all the states except Texas), and the 1979 ozone NAAQS (for Alabama, Missouri, and Tennessee) to the same extent that those obligations are currently being addressed by participation of the states' EGUs in the Group 2 trading program.

TABLE I.B–1—PROPOSED AND ILLUSTRATIVE CSAPR NO_X OZONE SEASON GROUP 3 STATE EMISSIONS BUDGETS FOR 2023 THROUGH 2026 CONTROL PERIODS *—Continued

State	Proposed emissions budgets for 2023 control period (tons)	Proposed emissions budgets for 2024 control period (tons)	Illustrative emissions budgets for 2025 control period (tons)	Illustrative emissions budgets for 2026 control period (tons)
Wyoming	9,125	8,573	8,573	4,490

* Further information on the state-level emissions budget calculations pertaining to Table I.B–1 is provided in Section VII.B.4 of this proposed rule as well as the Ozone Transport Policy Analysis Proposed Rule TSD. Further information on the proposed approach for allocating a portion of Utah's emissions budget for each control period to the existing EGU in the Uintah and Ouray Reservation within Utah's borders is provided in Section VII.B.9 of this proposed rule.

Beyond preset emissions budgets for the 2023 and 2024 control periods, the EPA also proposes to extend the Group 3 trading program budget-setting methodology used in the Revised CSAPR Update so as to routinely set emissions budgets for each future control period (beginning in 2025) in the year before that control period, with each emissions budget reflecting the latest available information on the composition and utilization of the EGU fleet at the time that emissions budget is determined (*see* Table VII.B.4.c–2 for illustrative examples of dynamic budget calculations that the EPA will publish in advance of each ozone season, effective for the 2025 control period and beyond). The stringency of the dynamic emissions budgets would simply reflect the stringency of the emissions control strategies selected in the rulemaking more consistently over time and ensure that the annual updates would eliminate emissions determined to be unlawful under the good neighbor provision. *See* Section VII.B of this proposed rule for additional discussion of EPA's proposed method for adjusting emissions budgets to ensure elimination of significant contribution from EGU sources in the linked upwind states.

As an enhancement to the structure of the trading program as originally promulgated in the Revised CSAPR Update, the EPA is also proposing to establish backstop daily emissions rates for coal steam units greater than or equal to 100 MW in covered states. Units emitting in excess of these daily rates would be subject to increased allowance surrender requirements under the trading program. The backstop daily emissions rates would work in tandem with the ozone season emissions budgets to offer downwind stakeholders a necessary measure of assurance that they will be protected on a daily basis during the ozone season by continuous operation of installed pollution controls. The EPA's experience with the CSAPR trading programs has revealed instances where EGUs have reduced their SCRs' performance on a given day, or across the entire ozone seasons in some cases, including high ozone days.[16] In addition to maintaining a mass-based seasonal requirement, the EPA proposes to require controls while maintaining as much compliance flexibility as possible through a unit-level emission rate designed to ensure that controls operate continuously and that required reductions occur on the highest ozone days. These trading program improvements also promote consistent emissions control performance across the power sector, which protects communities living in downwind ozone nonattainment areas from exceedances of the NAAQS that might otherwise occur.

The EPA proposes to include enforceable emissions standards that will apply during the ozone season (annually from May to September) for seven non-EGU industries in the promulgated FIPs to achieve the required emissions reductions in 23 states with remaining interstate transport obligations for the 2015 ozone NAAQS in 2026: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming. These requirements would apply to all existing emissions units and to any future emissions units constructed in the covered states after promulgation of the final rule. Thus, the emissions limits for non-EGU sources and associated compliance requirements would apply in all 23 states listed in this paragraph, even if certain of these states do not currently have existing emissions units within a particular industry.

Based on our evaluation of the time required to install controls at the types of non-EGU sources covered by this proposed rule, the EPA has identified the 2026 ozone season as the earliest compliance date possible for non-EGU emissions reductions. The EPA is therefore proposing to include non-EGU emissions reductions beginning in 2026. For sources located in the 23 states listed in the previous paragraph, The EPA proposes to require the emissions limits listed in Table I.B–2 for

[16] *See* 86 FR 23090. The EPA highlighted the Miami Fort Unit 7 (possessing a SCR) more than tripled its ozone-season NO_X emission rate between 2017 and 2019.

reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; the emissions limits listed in Table I.B–3 for kilns in Cement and Cement Product Manufacturing; the emissions limits listed in Table I.B–4 for boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; the emissions limits listed in Table I.B–5 for furnaces in Glass and Glass Product Manufacturing; and the emissions limits listed in Table I.B–6 for high-emitting equipment and large boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.

TABLE I.B–2—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR PIPELINE TRANSPORTATION OF NATURAL GAS

Engine type and fuel	Proposed NO_X emissions limit
Natural Gas Fired Four Stroke Rich Burn.	1.0 g/hp-hr.
Natural Gas Fired Four Stroke Lean Burn.	1.5 g/hp-hr.
Natural Gas Fired Two Stroke Lean Burn.	3.0 g/hp-hr.

TABLE I.B–3—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR KILN TYPES IN CEMENT AND CONCRETE PRODUCT MANUFACTURING

Kiln type	Proposed NO_X emissions limit (lb/ton of clinker)
Long Wet	4.0
Long Dry	3.0
Preheater	3.8
Precalciner	2.3
Preheater/Precalciner	2.8

The EPA is also proposing a source cap limit expressed in ton per day (tpd) of NO_X for each individual cement plant according to the following equation.[17]

$$CAP2015\ Ozone\ Transport = \frac{(KW\ x\ NW) + (KD\ x\ ND)}{(2000\frac{pounds}{ton}\ x\ 365\frac{days}{year})}$$

Where:

CAP2015 Ozone Transport = total allowable NO_X emissions from all cement kilns located at one cement plant, in tons per day, on a 30-operating day rolling average basis;

KD = 1.7 pounds NO_X per ton of clinker for dry preheater-precalciner or precalciner kilns;

KW = 3.4 pounds NO_X per ton of clinker for long wet kilns;

ND = the average annual production in tons of clinker plus one standard deviation for the three most recent calendar years from all dry preheater-precalciner or precalciner kilns located at one cement plant; and

NW = the average annual production in tons of clinker plus one standard deviation for the 3 most recent calendar years from all long wet kilns located at one cement plant.

An affected cement plant will need to comply with both the source cap limit and the specific NO_X emissions limits assigned to its individual kiln type(s). Refer to Section VII.C.2 of this proposed rule for additional information concerning the application of the source cap limit to this industry source group.

TABLE I.B–4—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR IRON AND STEEL AND FERROALLOY EMISSIONS UNITS

Emissions unit	Proposed NO_X emissions standard or requirement (lbs/hour or lb/mmBtu)
Blast Furnace	0.03 lb/mmBtu.
Basic Oxygen Furnace	0.07 lb/ton.
Electric Arc Furnace	0.15 lb/ton steel.
Ladle/tundish Preheaters	0.06 lb/mmBtu.
Reheat furnace	0.05 lb/mmBtu.
Annealing Furnace	0.06 lb/mmBtu.
Vacuum Degasser	0.03 lb/mmBtu.
Ladle Metallurgy Furnace	0.1 lb/ton.
Taconite production kilns	Work practice standard to install low NO_X technology/burners, test and set.
Coke ovens (charging and coking)	0.6 lb/ton of coal charged.
Coke ovens (pushing)	0.015 lb/ton of coal pushed.
Boilers—Coal	0.20 lb/mmBtu.
Boilers—Residual oil	0.20 lb/mmBtu.
Boilers—Distillate oil	0.12 lb/mmBtu.
Boilers—Natural gas	0.08 lb/mmBtu.

[17] Based on source cap equation at 30 TAC § 117.3123(b); January 14, 2009 (74 FR 1927), Docket ID No. EPA–R06–OAR–2007–1147, also *see https://wayback.archive-it.org/414/20210527223433/https://www.tceq.texas.gov/assets/public/legal/rules/rules/pdflib/117e.pdf.*

TABLE IV.B–5—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR FURNACE UNIT TYPES IN GLASS AND GLASS PRODUCT MANUFACTURING

Furnace type	Proposed NO_X emissions limit (lb/ton of glass produced)
Container Glass Manufacturing Furnace	4.0
Pressed/Blown Glass Manufacturing Furnace or Fiberglass Manufacturing Furnace	4.0
Flat Glass Manufacturing Furnace	9.2

TABLE I.B–6—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR HIGH-EMITTING EQUIPMENT AND LARGE BOILERS IN BASIC CHEMICAL MANUFACTURING, PETROLEUM AND COAL PRODUCTS MANUFACTURING, AND PULP, PAPER, AND PAPERBOARD MILLS

Unit type	Emissions limit (lbs NO_X/mmBtu)
Coal	0.20
Residual oil	0.20
Distillate oil	0.12
Natural gas	0.08

Refer to Section VII.C of this proposed rule for applicability criteria, compliance assurance requirements, and the EPA's rationale in proposing these emissions limits for each of the non-EGU industries covered by the proposed rule. In addition, the EPA requests comment on several topics regarding the implementation of emissions limits for non-EGU sources that are proposed in this rulemaking, including controls on emissions units and control installation timing. *See* Section VI.D.2.a of this proposed rule for a list of detailed questions on which the Agency is soliciting public comment.

The remainder of this preamble is organized as follows: Section III of this proposed rule outlines general applicability criteria for the proposed rule and describes the EPA's legal authority for this proposed rule, the relationship of the proposed rule to previous interstate ozone transport rulemakings, and the incremental costs and benefits of the proposed rule; Section IV of this proposed rule describes the human health and environmental challenges posed by interstate transport contributions to ozone air quality problems, as well as EPA's overall approach for addressing interstate transport for the 2015 ozone NAAQS in this proposed rule; Section V of this proposed rule describes the Agency's analyses of air quality data to inform this proposed rulemaking, including descriptions of the air quality modeling platform and emissions inventories used in the proposed rule, as well as EPA's methods for identifying downwind air quality problems and upwind states' ozone transport contributions to downwind states; Section VI of this proposed rule describes EPA's approach to quantifying upwind states' obligations in the form of EGU NO_X control stringencies and non-EGU emissions limits; Section VII of this proposed rule describes key elements of the implementation schedule for EGU and non-EGU emissions reductions requirements, including details regarding the revised aspects of the CSAPR NO_X Group 3 trading program and compliance deadlines, as well as regulatory requirements and compliance deadlines for non-EGU sources; Section VIII of this proposed rule discusses the environmental justice considerations of the proposed rule; Section IX of this proposed rule describes the expected costs, benefits, and other impacts of this proposed rule; Section X of this proposed rule provides a summary of proposed changes to the existing regulatory text; and Section XI of this proposed rule discusses the statutory and executive orders affecting this proposed rulemaking.

C. Costs and Benefits

A summary of the key results of the cost-benefit analysis that was prepared for this proposed rule is presented in Table I.C–1. Table I.C–1 presents estimates of the present values (PV) and equivalent annualized values (EAV), calculated using discount rates of 3 and 7 percent as directed by OMB's Circular A–4, of the health benefits, compliance costs, and net benefits of the proposed rule, in 2016 dollars, discounted to 2022. The estimated monetized net benefits are the estimated monetized benefits minus the estimated monetized costs of the proposed rule. These results present an incomplete overview of the effects of the proposal, because important categories of benefits—including benefits from reducing climate pollution, other types of air pollutants, and water pollution—were not monetized and are therefore not reflected in the cost-benefit tables. We anticipate that taking non-monetized effects into account would show the proposal to be more net beneficial than this table reflects.

TABLE I.C–1—ESTIMATED MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE PROPOSED RULE, 2023 THROUGH 2042

[Millions 2016$, discounted to 2022] [a]

	3% Discount rate	7% Discount rate
Present Value:		
Benefits [b]	250,000	150,000
Compliance Costs [c]	22,000	14,000
Net Benefits	220,000	130,000
Equivalent Annualized Value:		
Benefits	17,000	14,000
Compliance Costs	1,500	1,300

TABLE I.C–1—ESTIMATED MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE PROPOSED RULE, 2023 THROUGH 2042—Continued

[Millions 2016$, discounted to 2022] [a]

	3% Discount rate	7% Discount rate
Net Benefits	15,000	12,000

[a] Rows may not appear to add correctly due to rounding.

[b] The annualized present value of costs and benefits are calculated over a 20-year period from 2023 to 2042. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate benefits from reductions in CO_2 emissions. The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. See *Louisiana* v. *Biden*, No. 21–cv–01074–JDC–KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposal conducted pursuant to E.O. 12866. Please see Chapter 5, Section 5.2 of the RIA for more discussion. In addition, there are important unquantified water quality benefits and benefits associated with reductions in other air pollutants.

[c] The costs presented in this table are consistent with the costs presented in Chapter 4 of the RIA. To estimate these annualized costs, EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. Costs were calculated using a 3.76% real discount rate consistent with the rate used in IPM's objective function for cost-minimization.

As shown in Table I.C–1, the PV of the benefits, associated with reductions in $PM_{2.5}$ and ozone concentrations, of this proposed rule, discounted at a 3-percent discount rate, is estimated to be about $250,000 million, with an EAV of about $17,000 million. At a 7-percent discount rate, the PV of the benefits is estimated to be $150,000 million, with an EAV of about $14,000 million. The PV of the compliance costs, discounted at a 3-percent rate, is estimated to be about $22,000 million, with an EAV of about $1,500 million. At a 7-percent discount rate, the PV of the compliance costs is estimated to be about $14,000 million, with an EAV of about $1,300 million.

II. Public Participation

A. Written Comments

Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2021–0668 at *https://www.regulations.gov* (our preferred method), or the other methods identified in the **ADDRESSES** section. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit to EPA's docket at *https://www.regulations.gov* any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets.*

Due to public health concerns related to COVID–19, the EPA Docket Center and Reading Room are open to the public by appointment only. Our Docket Center staff also continues to provide remote customer service via email, phone, and webform. Hand deliveries or couriers will be received by scheduled appointment only. For further information and updates on EPA Docket Center services, please visit us online at *https://www.epa.gov/dockets.*

The EPA continues to carefully and continuously monitor information from the Centers for Disease Control and Prevention (CDC), local area health departments, and our Federal partners so that we can respond rapidly as conditions change regarding COVID–19.

B. Submitting Confidential Business Information

Do not submit information containing CBI to the EPA through *https://www.regulations.gov.* Clearly mark the part or all of the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, mark the outside of the digital storage media as CBI and then identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in *Instructions* earlier. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2. Our preferred method to receive CBI is for it to be transmitted to electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (*e.g.,* Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the OAQPS CBI Office using the email address, *oaqpscbi@epa.gov,* and should include clear CBI markings as described above. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link. If sending CBI information through the postal service, please send it to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2021–0668. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

C. Participation in Virtual Public Hearing

Please note that because of current CDC recommendations, as well as state and local orders for social distancing to limit the spread of COVID–19, the EPA cannot hold in-person public meetings at this time.

The EPA will begin pre-registering speakers for the hearing no later than 1 business day after publication of this document in the **Federal Register**. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/csapr/csapr-2015-ozone-naaqs.* The last day to pre-register to speak at the hearing will be April 21, 2022. The EPA will post a general agenda for the hearing that will list pre-registered speakers in approximate order at: *https://www.epa.gov/csapr/csapr-2015-ozone-naaqs.*

The virtual public hearing will be held on via teleconference on April 21, 2022. The virtual public hearing will convene at 10:00 a.m. Eastern Time (ET) and will conclude at 7:00 p.m. ET. The EPA may close a session 15 minutes after the last pre-registered speaker has testified if there are no additional speakers. For information or questions about the public hearing, please contact Ms. Holly DeJong at *Dejong.holly@epa.gov.* The EPA will announce further details at *https://www.epa.gov/csapr/csapr-2015-ozone-naaqs.*

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule.

Each commenter will have 5 minutes to provide oral testimony. The EPA encourages commenters to provide the EPA with a copy of their oral testimony electronically (via email) by emailing it to *Dejong.holly@epa.gov.* The EPA also recommends submitting the text of your oral comments as written comments to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations, but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral comments and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/csapr/csapr-2015-ozone-naaqs.* While the EPA expects the hearing to go forward as set forth above, please monitor our website or contact Ms. Holly DeJong at *Dejong.holly@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require the services of a translator or special accommodations such as audio description, please pre-register for the hearing and describe your needs by April 18, 2022. EPA may not be able to arrange accommodations without advanced notice.

III. General Information

A. Does this action apply to me?

This proposed rule affects EGU and non-EGU sources, and regulates the groups identified in Table III.A–1.

TABLE III.A–1—REGULATED GROUPS

Industry group	NAICS
Fossil fuel-fired electric power generation	221112
Pipeline Transportation of Natural Gas	4862
Cement and Concrete Product Manufacturing	3273
Iron and Steel Mills and Ferroalloy Manufacturing	3311
Glass and Glass Product Manufacturing	3272
Basic Chemical Manufacturing	3251
Petroleum and Coal Products Manufacturing	3241
Pulp, Paper, and Paperboard Mills	3221

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this proposed rule. This table lists the types of entities that the EPA is now aware could potentially be regulated by this proposed rule. Other types of entities not listed in the table could also be regulated. For example, the EPA is requesting comment in Section VI.B.3 of this proposed rule on potential control strategies for sources outside of the categories listed in the Table III.A.1, such as municipal waste combustors (MWCs). To determine whether your EGU entity is proposed to be regulated by this proposed rule, you should carefully examine the applicability criteria found in 40 CFR 97.1004, which the EPA is not proposing to alter in this proposed rule. If you have questions regarding the applicability of this proposed rule to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

B. What action is the Agency taking?

The EPA evaluated whether interstate ozone transport emissions from upwind states are significantly contributing to nonattainment, or interfering with maintenance, of the 2015 ozone NAAQS in any downwind state using the same 4-step interstate transport framework that was developed in previous ozone transport rulemakings. The EPA is proposing to find that emissions reductions are required from EGU and non-EGU sources in a total of 26 upwind states to eliminate significant contribution to downwind air quality problems for the 2015 ozone standard under the interstate transport provision of the CAA. The EPA will ensure that these NO_X emissions reductions are achieved by issuing proposed FIP requirements for 26 states: Alabama, Arkansas, California, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming.

The EPA is proposing to revise the existing CSAPR Group 3 Trading Program to include additional states beginning in the 2023 ozone season. EGUs in five states not currently covered by any CSAPR trading program for seasonal NO_X emissions—Delaware, Minnesota, Nevada, Utah, and Wyoming—would be added to the CSAPR Group 3 Trading Program under this proposed rule. EGUs in twelve states currently participating in the Group 3 Trading Program would remain in the program under this proposed rule: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. EGUs in eight states (Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin) will transition from the CSAPR Group 2 Trading Program to the CSAPR Group 3 Trading Program under this proposed rule beginning in the 2023 ozone season. The EPA proposes to establish control stringency levels reflecting installation of state-of-the-art combustion controls on certain covered EGU sources in emissions budgets beginning in the 2024 ozone season. The EPA proposes to establish control stringency levels reflecting installation of new SCR or SNCR controls on certain covered EGU sources in emissions budgets beginning in the 2026 ozone season.

As a complement to the ozone season emissions budgets, the EPA is also proposing to establish backstop daily emissions rates of 0.14 lb/mmBtu for coal-fired steam units greater than or equal to 100 MW in covered states. The backstop emissions rates will first apply in 2024 for coal-fired steam sources with existing SCRs, and in 2027 for those currently without SCRs.

In this proposed rule, the EPA is proposing to require emissions limitations for non-EGU sources in 23 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and

Wyoming. In these states, EPA is proposing to require emissions limitations for the following unit types in non-EGU industries: Furnaces in Glass and Glass Product Manufacturing; boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; kilns in Cement and Cement Product Manufacturing; reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; and high-emitting equipment and large boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mill. See Table III.A–1 for a list of NAICS codes for each entity included for regulation under this proposed rule.

The proposed rule would reduce the transport of ozone precursor emissions to downwind areas, which is protective of human health and the environment because acute and chronic exposure to ozone are both associated with negative health impacts. Ozone exposure is also associated with negative effects on ecosystems. Additional information on the human health and environmental benefits from the air quality issues addressed by this proposed rule are included in Section IV of this proposed rule.

C. What is the Agency's legal authority for taking this action?

1. Statutory Authority

The statutory authority for this proposed rule is provided by the CAA as amended (42 U.S.C. 7401 *et seq.*). Specifically, sections 110 and 301 of the CAA provide the primary statutory underpinnings for this proposed rule. The most relevant portions of CAA section 110 are subsections 110(a)(1), 110(a)(2) (including 110(a)(2)(D)(i)(I)), 110(c)(1), and 110(k)(6)).

CAA section 110(a)(1) provides that states must make SIP submissions ''within 3 years (or such shorter period as the Administrator may prescribe) after the promulgation of a national primary ambient air quality standard (or any revision thereof),'' and that these SIP submissions are to provide for the ''implementation, maintenance, and enforcement'' of such NAAQS.[18] The statute directly imposes on states the duty to make these SIP submissions, and the requirement to make the submissions is not conditioned upon the EPA taking any action other than promulgating a new or revised NAAQS.[19]

The EPA has historically referred to SIP submissions made for the purpose of satisfying the applicable requirements of CAA sections 110(a)(1) and 110(a)(2) as ''infrastructure SIP'' or ''iSIP'' submissions. CAA section 110(a)(1) addresses the timing and general requirements for iSIP submissions, and CAA section 110(a)(2) provides more details concerning the required content of these submissions.[20] It includes a list of specific elements that ''[e]ach such plan'' must address.[21]

CAA section 110(c)(1) requires the Administrator to promulgate a FIP at any time within two years after the Administrator: (1) Finds that a state has failed to make a required SIP submission; (2) finds a SIP submission to be incomplete pursuant to CAA section 110(k)(1)(C); or (3) disapproves a SIP submission. This obligation applies unless the state corrects the deficiency through a SIP revision that the Administrator approves before the FIP is promulgated.[22]

CAA section 110(a)(2)(D)(i)(I), also known as the ''good neighbor'' provision, provides the primary basis for this proposed rule.[23] It requires that each state SIP include provisions sufficient to ''prohibit[ ], 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 [NAAQS].'' [24] The EPA often refers to the emissions reduction requirements under this provision as ''good neighbor obligations'' and submissions addressing these requirements as ''good neighbor SIPs.''

Once EPA promulgates a NAAQS, the EPA must designate areas as being in ''attainment'' or ''nonattainment'' of the NAAQS, or ''unclassifiable.'' CAA section 107(d).[25] For ozone, nonattainment is further split into five classifications based on the severity of the violation—Marginal, Moderate, Serious, Severe, or Extreme. Higher classifications provide states with progressively more time to attain while imposing progressively more stringent control requirements. *See* CAA sections 181, 182.[26] In general, states with nonattainment areas classified as Moderate or higher must submit plans to EPA to bring these areas into attainment according to the statutory schedule. CAA section 182.[27] If an area fails to attain the NAAQS by the attainment date associated with its classification, it is ''bumped up'' to the next classification. CAA section 181(b).[28]

Section 301(a)(1) of the CAA gives the Administrator the general authority to prescribe such regulations as are necessary to carry out functions under the Act.[29] Pursuant to this section, EPA has authority to clarify the applicability of CAA requirements and undertake other rulemaking action as necessary to implement CAA requirements. CAA section 301 affords the Agency any additional authority that may be needed in order to make certain other changes to its regulations under 40 CFR parts 52, 75, 78, and 97, in order to effectuate the purposes of the Act. Such changes are discussed in Section X of this proposed rule.

Section 110(k)(6) of the CAA gives the Administrator authority, without any further submission from a state, to revise certain prior actions, including actions to approve SIPs, upon determining that those actions were in error.[30] The EPA proposes to make an error correction under CAA section 110(k)(6) with respect to its prior approval of the 2015 ozone transport SIP submission from the State of Delaware. This is further discussed in Section IV.C.1 of the proposed rule.

Tribes are not required to submit state implementation plans. However, as explained in EPA's regulations outlining Tribal Clean Air Act authority, the EPA is authorized to promulgate FIPs for Indian country as necessary or appropriate to protect air quality if a tribe does not submit, and obtain EPA approval of, an implementation plan. *See* 40 CFR 49.11(a); *see also* CAA section 301(d)(4).[31] In this proposed rule, the EPA proposes an ''appropriate or necessary'' finding under CAA section 301(d) and proposes tribal FIP(s) as necessary to implement the relevant requirements. This is further discussed in Section IV.C.2 of the proposed rule.

[18] 42 U.S.C. 7410(a)(1).

[19] *See EPA* v. *EME Homer City Generation, L.P.*, 572 U.S. 489, 509–10 (2014).

[20] 42 U.S.C. 7410(a)(2).

[21] EPA's general approach to infrastructure SIP submissions is explained in greater detail in individual notices acting or proposing to act on state infrastructure SIP submissions and in guidance. *See, e.g.,* Memorandum from Stephen D. Page on Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and 110(a)(2) (September 13, 2013).

[22] 42 U.S.C. 7410(c)(1).

[23] 42 U.S.C. 7410(a)(2)(D)(i)(I).

[24] *Id.*

[25] 42 U.S.C. 7407(d).

[26] 42 U.S.C. 7511, 7511a.

[27] 42 U.S.C. 7511a.

[28] 42 U.S.C. 7511(b).

[29] 42 U.S.C. 7601(a)(1).

[30] 42 U.S.C. 7410(k)(6).

[31] 42 U.S.C. 7601(d)(4).

D. What actions has EPA previously issued to address regional ozone transport?

The EPA has issued several major rules interpreting and clarifying the requirements of CAA section 110(a)(2)(D)(i)(I) with respect to the regional transport of ozone. These rules, and the associated court decisions addressing these rules, summarized here, provide important direction regarding the requirements of CAA section 110(a)(2)(D)(i)(I).

The ''NO_X SIP Call,'' promulgated in 1998, addressed the good neighbor provision for the 1979 1-hour ozone NAAQS.[32] The rule required 22 states and the District of Columbia to amend their SIPs to reduce NO_X emissions that contribute to ozone nonattainment in downwind states. The EPA set ozone season NO_X budgets for each state, and the states were given the option to participate in a regional allowance trading program, known as the NO_X Budget Trading Program.[33] The D.C. Circuit largely upheld the NO_X SIP Call in *Michigan* v. *EPA,* 213 F.3d 663 (D.C. Cir. 2000), *cert. denied,* 532 U.S. 904 (2001).

EPA's next rule addressing the good neighbor provision, the Clean Air Interstate Rule (CAIR), was promulgated in 2005 and addressed both the 1997 fine particulate matter ($PM_{2.5}$) NAAQS and 1997 ozone NAAQS.[34] CAIR required SIP revisions in 28 states and the District of Columbia to reduce emissions of sulfur dioxide (SO_2) or NO_X—important precursors of regionally transported $PM_{2.5}$ (SO_2 and annual NO_X) and ozone (summer-time NO_X). As in the NO_X SIP Call, states were given the option to participate in regional trading programs to achieve the reductions. When the EPA promulgated the final CAIR in 2005, the EPA also issued findings that states nationwide had failed to submit SIPs to address the requirements of CAA section 110(a)(2)(D)(i) with respect to the 1997 $PM_{2.5}$ and 1997 ozone NAAQS.[35] On March 15, 2006, the EPA promulgated FIPs to implement the emissions reductions required by CAIR.[36] CAIR was remanded to EPA by the D.C. Circuit in *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir. 2008), *modified on reh'g,* 550 F.3d 1176. For more information on the legal issues underlying CAIR and the D.C. Circuit's holding in *North Carolina,* refer to the preamble of the CSAPR rule.[37]

In 2011, the EPA promulgated CSAPR to address the issues raised by the remand of CAIR. CSAPR addressed the two NAAQS at issue in CAIR and additionally addressed the good neighbor provision for the 2006 $PM_{2.5}$ NAAQS.[38] CSAPR required 28 states to reduce SO_2 emissions, annual NO_X emissions, or ozone season NO_X emissions that significantly contribute to other states' nonattainment or interfere with other states' abilities to maintain these air quality standards.[39] To align implementation with the applicable attainment deadlines, the EPA promulgated FIPs for each of the 28 states covered by CSAPR. The FIPs require EGUs in the covered states to participate in regional trading programs to achieve the necessary emissions reductions. Each state can submit a good neighbor SIP at any time that, if approved by EPA, would replace the CSAPR FIP for that state.

CSAPR was the subject of an adverse decision by the D.C. Circuit in August 2012.[40] However, this decision was reversed in April 2014 by the Supreme Court, which largely upheld the rule, including EPA's approach to addressing interstate transport in CSAPR. *EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. 489 (2014) (*EME Homer City I*). The rule was remanded to the D.C. Circuit to consider claims not addressed by the Supreme Court. *Id.* In July 2015 the D.C. Circuit generally affirmed EPA's interpretation of various statutory provisions and EPA's technical decisions. *EME Homer City Generation, L.P.* v. *EPA,* 795 F.3d 118 (2015) (*EME Homer City II*). However, the court remanded the rule without vacatur for reconsideration of EPA's emissions budgets for certain states, which the court found may have over-controlled those states' emissions with respect to the downwind air quality problems to which the states were linked. *Id.* at 129–30, 138. For more information on the legal issues associated with CSAPR and the Supreme Court's and D.C. Circuit's decisions in the *EME Homer City* litigation, refer to the preamble of the CSAPR Update.[41]

In 2016, the EPA promulgated the CSAPR Update to address interstate transport of ozone pollution with respect to the 2008 ozone NAAQS.[42] The final rule updated the CSAPR ozone season NO_X emissions budgets for 22 states to achieve cost-effective and immediately feasible NO_X emissions reductions from EGUs within those states.[43] The EPA aligned the analysis and implementation of the CSAPR Update with the 2017 ozone season in order to assist downwind states with timely attainment of the 2008 ozone NAAQS.[44] The CSAPR Update implemented the budgets through FIPs requiring sources to participate in a revised CSAPR NO_X ozone season trading program beginning with the 2017 ozone season. As under CSAPR, each state could submit a good neighbor SIP at any time that, if approved by the EPA, would replace the CSAPR Update FIP for that state. The final CSAPR Update also addressed the remand by the D.C. Circuit of certain states' CSAPR phase 2 ozone season NO_X emissions budgets in *EME Homer City II.*

In December 2018, the EPA promulgated the CSAPR ''Close-Out,'' which determined that no further enforceable reductions in emissions of NO_X were required with respect to the

[32] *Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone,* 63 FR 57356 (Oct. 27, 1998). As originally promulgated, the NO_X SIP Call also addressed good neighbor obligations under the 1997 8-hour ozone NAAQS, but EPA subsequently stayed and later rescinded the rule's provisions with respect to that standard. *See* 84 FR 8422 (March 8, 2019).

[33] ''Allowance Trading,'' sometimes referred to as ''cap and trade,'' is an approach to reducing pollution that has been used successfully to protect human health and the environment. The design elements of EPA's most recent trading programs are discussed in Section VII.B.1.a of this proposed rule.

[34] *Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the* NO_X *SIP Call,* 70 FR 25162 (May 12, 2005).

[35] 70 FR 21147 (April 25, 2005).

[36] 71 FR 25328 (April 28, 2006).

[37] *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals,* 76 FR 48208, 48217 (August 8, 2011).

[38] 76 FR 48208.

[39] CSAPR was revised by several rulemakings after its initial promulgation in order to revise certain states' budgets and to promulgate FIPs for five additional states addressing the good neighbor obligation for the 1997 ozone NAAQS. *See* 76 FR 80760 (December 27, 2011); 77 FR 10324 (February 21, 2012); 77 FR 34830 (June 12, 2012).

[40] On August 21, 2012, the D.C. Circuit issued a decision in *EME Homer City Generation, L.P.* v. *EPA,* 696 F.3d 7 (D.C. Cir. 2012), vacating CSAPR. The EPA sought review with the D.C. Circuit *en banc* and the D.C. Circuit declined to consider EPA's appeal *en banc. EME Homer City Generation, L.P.* v. *EPA,* No. 11–1302 (D.C. Cir. January 24, 2013), ECF No. 1417012 (denying EPA's motion for rehearing en banc).

[41] *Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS,* 81 FR 74504, 74511 (October 26, 2016).

[42] 81 FR 74504.

[43] One state, Kansas, was made newly subject to ozone season NO_X requirements by the CSAPR Update. All other CSAPR Update states were already subject to ozone season NO_X requirements under CSAPR.

[44] 81 FR 74516. EPA's final 2008 Ozone NAAQS SIP Requirements Rule, 80 FR 12264, 12268 (March 6, 2015), revised the attainment deadline for ozone nonattainment areas designated as Moderate to July 20, 2018. *See* 40 CFR 51.1103. In order to demonstrate attainment by this deadline, states were required to rely on design values calculated using ozone season data from 2015 through 2017, since the July 20, 2018, deadline did not afford enough time for measured data of the full 2018 ozone season.

2008 ozone NAAQS for 20 of the 22 eastern states covered by the CSAPR Update, and reflected that determination in revisions to the existing state-specific sections of the CSAPR Update regulations for those states.[45]

The CSAPR Update and the CSAPR Close-Out were both subject to legal challenges in the D.C. Circuit. *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019) (*Wisconsin*); *New York* v. *EPA,* 781 Fed. App'x 4 (D.C. Cir. 2019) (*New York*). In September 2019, the D.C. Circuit upheld the CSAPR Update in virtually all respects but remanded the rule because it was partial in nature and did not fully eliminate upwind states' significant contribution to nonattainment or interference with maintenance of the 2008 ozone NAAQS by ''the relevant downwind attainment deadlines'' in the CAA. *Wisconsin,* 938 F.3d at 313–15. In October 2019, the D.C. Circuit vacated the CSAPR Close-Out on the same grounds that it remanded the CSAPR Update in *Wisconsin,* specifically that the Close-Out rule did not address good neighbor obligations by ''the next applicable attainment date'' of downwind states. *New York,* 781 Fed. App'x at 7.[46]

In response to the *Wisconsin* remand of the CSAPR Update and the *New York* vacatur of the CSAPR Close-Out, the EPA promulgated the Revised CSAPR Update on April 30, 2021.[47] The Revised CSAPR Update found that the CSAPR Update was a full remedy for nine of the covered states. For the 12 remaining states, the EPA found that their projected 2021 ozone season NO_X emissions significantly contribute to downwind states' nonattainment or maintenance problems. The EPA issued new or amended FIPs for these 12 states and required implementation of revised emissions budgets for EGUs beginning with the 2021 ozone season. Based on EPA's assessment of remaining air quality issues and additional emissions control strategies for EGUs and emissions sources in other industry sectors (non-EGUs), the EPA determined that the NO_X emissions reductions achieved by the Revised CSAPR Update fully eliminated these states' significant contributions to downwind air quality problems for the 2008 ozone NAAQS. As under the CSAPR and the CSAPR Update, each state can submit a good neighbor SIP at any time that, if approved by EPA, would replace the Revised CSAPR Update FIP for that state.[48]

IV. Air Quality Issues Addressed and Overall Approach for the Proposed Rule

A. The Interstate Ozone Transport Air Quality Challenge

1. Nature of Ozone and the Ozone NAAQS

Ground-level ozone is not emitted directly into the air but is created by chemical reactions between NO_X and volatile organic compounds (VOCs) in the presence of sunlight. Emissions from electric utilities and industrial facilities, motor vehicles, gasoline vapors, and chemical solvents are some of the major sources of NO_X and VOCs.

Because ground-level ozone formation increases with temperature and sunlight, ozone levels are generally higher during the summer months. Increased temperature also increases emissions of volatile man-made and biogenic organics and can also indirectly increase NO_X emissions (*e.g.,* increased electricity generation for air conditioning).

On October 1, 2015, the EPA strengthened the primary and secondary ozone standards to 70 ppb as an 8-hour level.[49] Specifically, the standards require that the 3-year average of the fourth highest 24-hour maximum 8-hour average ozone concentration may not exceed 70 ppb as a truncated value (*i.e.,* digits to right of decimal removed).[50] In general, areas that exceed the ozone standard are designated as nonattainment areas, pursuant to the designations process under CAA section 107, and are subject to heightened planning requirements depending on the degree of severity of their nonattainment classification, *see* CAA sections 181, 182.

In the process of setting the 2015 ozone NAAQS, the EPA noted that the conditions conducive to the formation of ozone (*i.e.,* seasonally-dependent factors such as ambient temperature, strength of solar insolation, and length of day) differ by location, and that the Agency believes it is important that ozone monitors operate during all periods when there is a reasonable possibility of ambient levels approaching the level of the NAAQS. At that time, the EPA stated that ambient ozone concentrations in many areas could approach or exceed the level of the NAAQS, more frequently and during more months of the year compared with the historical ozone season monitoring lengths. Consequently, the EPA extended the ozone monitoring season for many locations. *See* 80 FR 65416 for more details.

Furthermore, the EPA stated that in addition to being affected by changing emissions, future ozone concentrations may also be affected by climate change. Modeling studies in the EPA's Interim Assessment (U.S. EPA, 2009a) that are cited in support of the 2009 Endangerment Finding under CAA section 202(a) (74 FR 66496, Dec. 15, 2009) as well as a recent assessment of potential climate change impacts (Fann et al., 2015) project that climate change may lead to future increases in summer ozone concentrations across the contiguous U.S.[51] (80 FR 65300). The increase in ozone results from changes in local weather conditions, including temperature and atmospheric circulation patterns, as well as changes in ozone precursor emissions that are influenced by meteorology (Nolte et al., 2018). While the projected impact may not be uniform, climate change has the potential to increase average summertime ozone relative to a future without climate change.[52] [53] [54] Climate

[45] *Determination Regarding Good Neighbor Obligations for the 2008 Ozone National Ambient Air Quality Standard,* 83 FR 65878, 65882 (Dec. 21, 2018). After promulgating the CSAPR Update and before promulgating the CSAPR Close-Out, the EPA approved a SIP from Kentucky resolving the Commonwealth's good neighbor obligations for the 2008 ozone NAAQS. 83 FR 33730 (July 17, 2018). In the Revised CSAPR Update, the EPA made an error correction under CAA section 110(k)(6) to convert this approval to a disapproval, because the Kentucky approval relied on the same analysis which the D.C. Circuit determined to be unlawful in the CSAPR Close-Out.

[46] Subsequently, the D.C. Circuit made clear in a decision reviewing EPA's denial of a petition under CAA section 126 that the holding in *Wisconsin* regarding alignment with downwind area's attainment schedules applies with equal force to the Marginal area attainment date established under CAA section 181(a). *See Maryland* v. *EPA,* 958 F.3d 1185, 1203–04 (D.C. Cir. 2020).

[47] *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS,* 86 FR 23054 (April 30, 2021).

[48] The Revised CSAPR Update is currently subject to a petition for judicial review pending in the D.C. Circuit Court of Appeals, *Midwest Ozone Group* v. *EPA,* No. 21–1146 (D.C. Cir. June 25, 2021).

[49] 80 FR 65291.

[50] 40 CFR part 50, Appendix P to part 50

[51] These modeling studies are based on coupled global climate and regional air quality models and are designed to assess the sensitivity of U.S. air quality to climate change. A wide range of future climate scenarios and future years have been modeled and there can be variations in the expected response in U.S. O^3 by scenario and across models and years, within the overall signal of higher summer O^3 concentrations in a warmer climate.

[52] Fann NL, Nolte CG, Sarofim MC, Martinich J, Nassikas NJ. Associations Between Simulated Future Changes in Climate, Air Quality, and Human Health. JAMA Netw Open. 2021;4(1):e2032064. doi: 10.1001/jamanetworkopen.2020.32064.

[53] Christopher G Nolte, Tanya L Spero, Jared H Bowden, Marcus C Sarofim, Jeremy Martinich, Megan S Mallard. Regional temperature-ozone relationships across the U.S. under multiple climate and emissions scenarios. J Air Waste Manag Assoc. 2021 Oct;71(10):1251–1264. doi: 10.1080/10962247.2021.1970048.

change has the potential to offset some of the improvements in ozone air quality, and therefore some of the improvements in public health, that are expected from reductions in emissions of ozone precursors (80 FR 65300).

2. Ozone Transport

Studies have established that ozone formation, atmospheric residence, and transport occur on a regional scale (*i.e.,* thousands of kilometers) over much of the U.S.[55] While substantial progress has been made in reducing ozone in many areas, the interstate transport of ozone precursor emissions remains an important contributor to peak ozone concentrations and high-ozone days during the summer ozone season.

The EPA has previously concluded in the NO_X SIP Call, CAIR, CSAPR, the CSAPR Update, and the Revised CSAPR Update that a regional NO_X control strategy would be effective in reducing regional-scale transport of ozone precursor emissions. NO_X emissions can be transported downwind as NO_X or as ozone after transformation in the atmosphere. In any given location, ozone pollution levels are impacted by a combination of background ozone concentration, local emissions, and emissions from upwind sources resulting from ozone transport. Downwind states' ability to meet health-based air quality standards such as the NAAQS is challenged by the transport of ozone pollution across state borders. For example, ozone assessments conducted for the October 2015 Regulatory Impact Analysis of the Final Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone continue to show the importance of NO_X emissions for ozone transport. This analysis is included in the docket for this proposal.

Further, studies have found that EGU NO_X emissions reductions can be effective in reducing individual 8-hour peak ozone concentrations and in reducing 8-hour peak ozone concentrations averaged across the ozone season. For example, a study that evaluates the effectiveness on ozone concentrations of EGU NO_X reductions achieved under the NO_X Budget Trading Program (*i.e.,* the NO_X SIP Call) shows that regulating NO_X emissions in that program was highly effective in reducing ozone concentrations during the ozone season.[56]

Previous regional ozone transport efforts, including the NO_X SIP Call, CAIR, CSAPR, the CSAPR Update, and the Revised CSAPR Update, required ozone season NO_X reductions from EGU sources to address interstate transport of ozone. Together with NO_X, EPA has also identified VOCs as a precursor in forming ground-level ozone. Ozone formation chemistry can be ''NO_X-limited,'' where ozone production is primarily determined by the amount of NO_X emissions or ''VOC-limited,'' where ozone production is primarily determined by the amount of VOC emissions.[57] The EPA and others have long regarded NO_X to be the more significant ozone precursor in the context of interstate ozone transport.[58]

The EPA has determined that the regulation of VOCs as an ozone precursor is not necessary to eliminate significant contribution of ozone transport to downwind areas in this proposed rule. As described in Section VI.A of this proposed rule, the EPA examined the results of the contribution modeling performed for this rule to identify the portion of the ozone contribution attributable to anthropogenic NO_X emissions versus VOC emissions from each linked upwind state to each downwind receptor. Our analysis of the ozone contribution from upwind states subject to regulation under this proposed rule demonstrates that the vast majority of the downwind air quality areas are NO_X-limited, rather than VOC-limited. Therefore, the proposed rule's strategy for reducing regional-scale transport of ozone targets NO_X emissions from stationary sources to achieve the most effective reductions of ozone transport over the geography of the affected downwind areas.

Commenters on prior ozone transport rules have asserted that VOC emissions harm underserved and overburdened communities experiencing disproportionate environmental health burdens and facing other environmental injustices. The EPA acknowledges that VOCs can contain toxic chemicals that are detrimental to public health. The EPA conducted a demographic analysis as part of the regulatory impact analysis for the 2015 revisions to the primary and secondary ozone NAAQS. This analysis, which is included in the docket for this proposed rulemaking, found greater representation of minority populations in areas with poor air quality relative to the revised ozone standard than in the U.S. as a whole. The EPA concluded that populations in these areas would be expected to benefit from implementation of future air pollution control actions from state and local air agencies in implementing the strengthened standard. This proposed rule is an example of air pollution control actions implemented by the federal government in support of the more stringent 2015 ozone NAAQS, and populations living in downwind ozone nonattainment areas are expected to benefit from improved air quality that will result from reducing ozone transport. Further discussion of the environmental justice impacts of this proposed rule is located in Section VIII of this proposed rule and in the accompanying regulatory impact analysis, titled ''Regulatory Impact Analysis for the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard'' [EPA–452/D–22–001], which is available in the docket for this rulemaking.

The Agency regulates exposure to toxic pollutant concentrations and ambient exposure to criteria pollutants other than ozone through other sections of the Act, such as the regulation of hazardous air pollutants under CAA section 112 or the process for revising and implementing the NAAQS under CAA sections 107–110. The purpose of the proposed rulemaking is to protect public health and the environment by eliminating significant contribution from 26 states to nonattainment or maintenance of the 2015 ozone NAAQS in order to meet the requirements of the CAA's interstate transport provision. In this proposed rule, the EPA continues to observe that requiring NO_X emissions reductions from stationary sources is an effective strategy for reducing regional ozone transport in the U.S.

In Section VI of this proposed rule, EPA describes the multi-factor test that is used to determine NO_X emissions reductions that are cost-effective and reduce interstate transport of ground-level ozone. Our analysis indicates that the EGU and non-EGU control requirements proposed in this rule will provide meaningful improvements in air quality at the downwind receptors. Based on the implementation schedule

[54] Nolte, C.G., P.D. Dolwick, N. Fann, L.W. Horowitz, V. Naik, R.W. Pinder, T.L. Spero, D.A. Winner, and L.H. Ziska, 2018: Air Quality. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 512–538. doi: 10.7930/NCA4.2018.CH13.

[55] Bergin, M.S. et al. (2007) Regional air quality: Local and interstate impacts of NO_X and SO_2 emissions on ozone and fine particulate matter in the eastern United States. Environmental Sci & Tech. 41: 4677–4689.

[56] Butler, et al., ''Response of Ozone and Nitrate to Stationary Source Reductions in the Eastern USA''. *Atmospheric Environment,* 2011.

[57] ''Ozone Air Pollution.'' *Introduction to Atmospheric Chemistry,* by DANIEL J. JACOB, Princeton University Press, PRINCETON, NEW JERSEY, 1999, pp. 231–244.

[58] 81 FR 74514.

established in Section VII.A of this proposed rule, the EPA proposes to determine that the regulatory requirements included in the proposed rule are as expeditious as practicable and are aligned with the attainment schedule of downwind areas.

3. Health and Environmental Effects

Exposure to ambient ozone causes a variety of negative effects on human health, vegetation, and ecosystems. In humans, acute and chronic exposure to ozone is associated with premature mortality and a number of morbidity effects, such as asthma exacerbation. In ecosystems, ozone exposure causes visible foliar injury, decreases plant growth, and affects ecosystem community composition. *See* EPA's October 2015 Regulatory Impact Analysis of the Final Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone [59] in the docket for this proposal for more information on the human health and ecosystem effects associated with ambient ozone exposure.

B. Proposed Rule Approach

1. The 4-Step Interstate Transport Framework

The EPA first developed a multi-step process to address the requirements of the good neighbor provision in the NO_X SIP Call and CAIR. The Agency built upon this framework and further refined the methodology for addressing interstate transport obligations in subsequent rules such as CSAPR, the CSAPR Update, and the Revised CSAPR Update.[60] In CSAPR, the EPA first articulated a ''4-step framework'' within which to assess interstate transport obligations for ozone. In this proposed action to address interstate transport obligations for the 2015 ozone NAAQS, the EPA is again utilizing the 4-step interstate transport framework. These steps are: (1) Identifying downwind receptors that are expected to have problems attaining the NAAQS (nonattainment receptors) or maintaining the NAAQS (maintenance receptors); (2) determining which upwind states are ''linked'' to these identified downwind receptors based on a numerical contribution threshold; (3) for states linked to downwind air quality problems, identifying upwind emissions on a statewide basis that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS, considering cost- and air quality-based factors; and (4) for upwind states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any downwind state, implementing the necessary emissions reductions through enforceable measures.

a. Step 1 Approach

The EPA proposes to continue to apply the method of the CSAPR Update and the Revised CSAPR Update for identifying nonattainment and maintenance receptors. In the Revised CSAPR Update, the EPA assessed downwind air quality problems using modeled future air quality concentrations for an analytic year aligned with the relevant attainment deadline for the NAAQS under consideration in that rulemaking.[61] Similarly, in CSAPR, downwind air quality problems were assessed using modeled future air quality concentrations for a year aligned with attainment deadlines for the NAAQS considered in that rulemaking. The base case scenario provides an assessment of future air quality conditions that generally accounts for enforceable ''on-the-books'' emissions reductions and provides the most up-to-date forecast of what future emissions would resemble, in the absence of the transport policy in the proposed rule under evaluation. Downwind air quality problems are identified as the locations of monitoring sites that are projected to be unable to attain the NAAQS (''nonattainment receptors'') or as the locations of monitoring sites that are projected to be unable to maintain the NAAQS (''maintenance receptors''). In the CSAPR Update and the Revised CSAPR Update, unlike CSAPR,[62] the EPA also considered currently available monitored air quality data to further inform the identification of projected downwind air quality problems. These same considerations are included for this proposal. Further details regarding the application of Step 1 of the 4-step interstate transport framework in this proposal are described in Section V.D of this proposed rule.

b. Step 2 Approach

The EPA proposes to apply the same approach for identifying which states are contributing to downwind nonattainment and maintenance receptors as it has applied in the three prior CSAPR rulemakings. CSAPR, the CSAPR Update, and the Revised CSAPR Update used a screening threshold of 1 percent of the NAAQS to identify upwind states that were ''linked'' to downwind air pollution problems. States with contributions greater than or equal to the threshold for at least one downwind nonattainment or maintenance receptor identified in Step 1 were identified as needing further evaluation of their good neighbor obligations to downwind states.[63] The EPA evaluated each state's contribution based on the average relative downwind impact calculated over multiple days.[64] States whose air quality impacts to all downwind receptors were below this threshold did not require further evaluation for actions to address transport. In other words, the EPA determined that these states did not contribute to downwind air quality problems and therefore had no emissions reduction obligations under the good neighbor provision. The EPA applies a contribution screening threshold because many downwind ozone nonattainment areas receive transport contributions from a number of upwind states. While the proportion of contribution from a single upwind state may be relatively small, the effect of collective contribution resulting from multiple upwind states may substantially contribute to nonattainment of or interference with maintenance of the NAAQS in downwind areas. The preambles to the

[59] Available at *https://www.epa.gov/sites/default/files/2016-02/documents/20151001ria.pdf.*

[60] *See* CSAPR, Final Rule, 76 FR 48208, 48248–48249 (August 8, 2011); CSAPR Update, Final Rule, 81 FR 74504, 74517–74521 (October 26, 2016).

[61] Specifically, the EPA analyzed 2021 to align with the attainment date for areas classified as Severe nonattainment for the 2008 ozone NAAQS, and because the last full ozone season before that date, in 2020, was already in the past.

[62] In CSAPR, the EPA did not use current monitored air quality conditions, because that data was influenced by the invalidated CAIR rule, which the EPA was replacing with CSAPR. *See* 81 FR 74506, 74531. As the EPA is not replacing an existing transport program in this proposed rule, the Agency proposes to once again consider current monitored data as part of the process for identifying projected receptors for this rulemaking.

[63] For ozone, the impacts include those from VOC and NO_X from all sectors.

[64] The number of days used in calculating the average contribution metric has historically been determined in a manner that is generally consistent with EPA's recommendations for projecting future year ozone design values. Our ozone attainment demonstration modeling guidance at the time of CSAPR recommended using all model-predicted days above the NAAQS to calculate future year design values (*https://www3.epa.gov/ttn/scram/guidance/guide/final-03-pm-rh-guidance.pdf*). In 2014, the EPA issued draft revised guidance that changed the recommended number of days to the top-10 model predicted days (*https://www3.epa.gov/ttn/scram/guidance/guide/Draft-O3-PM-RH-Modeling_Guidance-2014.pdf*). For the CSAPR Update, the EPA transitioned to calculating design values based on this draft revised approach. The revised modeling guidance was finalized in 2019 and, in this regard, EPA is calculating both the ozone design values and the contributions based on a top-10 day approach (*https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf*).

proposed and final CSAPR rules discuss the use of the 1 percent threshold for CSAPR. *See* 75 FR 45237 (August 2, 2010); 76 FR 48238 (August 8, 2011). The same metric is discussed in the CSAPR Update, *see* 81 FR 74538, and in the Revised CSAPR Update, *see* 86 FR 23054. In this proposed rule, the EPA updated the air quality modeling data used for determining contributions at Step 2 of the four-step interstate transport framework. The EPA otherwise continues to find that this threshold is appropriate to continue to apply for the 2015 ozone NAAQS. This proposal's application of the Step 2 approach is comprehensively described in Section V of this proposed rule.

c. Step 3 Approach

The EPA proposes to continue to apply the same approach as the prior three CSAPR rulemakings for evaluating ''significant contribution'' at Step 3.[65] For states that are linked in Step 3 to downwind air quality problems, CSAPR, the CSAPR Update, and the Revised CSAPR Update evaluated NO_X reduction potential, cost, and downwind air quality improvements available at various mitigation technology breakpoints (represented by cost thresholds) in the multi-factor test. In CSAPR, the CSAPR Update, and the Revised CSAPR Update, the EPA selected the technology breakpoint (represented by a cost threshold) that, in general, maximized cost-effectiveness—*i.e.,* that achieved a reasonable balance of incremental NO_X reduction potential and corresponding downwind ozone air quality improvements, relative to the other emissions budget levels evaluated. *See, e.g.,* 81 FR 74550. The EPA determined the level of emissions reductions associated with that level of control stringency to constitute significant contribution to nonattainment or interfere with maintenance of a NAAQS downwind. *See, e.g.,* 86 FR 23116. This approach was upheld by the U.S. Supreme Court in *EPA* v. *EME Homer City*.[66]

The EPA proposes in this action to apply this approach to identify EGU and non-EGU NO_X control stringencies necessary to address significant contribution for the 2015 ozone NAAQS. The EPA applies a multifactor assessment using cost-thresholds, total emissions reduction potential, and downwind air quality effects as key factors in determining a reasonable balance of NO_X controls in light of the downwind air quality problems. EPA's evaluation of available NO_X mitigation strategies for EGUs focuses on the same core set of measures as prior transport rules, and the EPA proposes a control stringency for EGUs from these measures that is commensurate with the nature of the ongoing ozone nonattainment and maintenance problems observed for the 2015 ozone NAAQS. Similarly, in this action, the EPA includes other industrial sources (non-EGUs) in its Step 3 analysis and proposes emissions limitations for certain non-EGU sources as needed to eliminate significant contribution and interference with maintenance. The available reductions and cost-levels for the non-EGU stringency is generally commensurate with the control strategy for EGUs.

In CSAPR, the CSAPR Update, and the Revised CSAPR Update, EPA focused its Step 3 analysis on EGUs. In the Revised CSAPR Update, in response to the *Wisconsin* decision's finding that the EPA had not adequately evaluated potential non-EGU reductions, *see* 938 F.3d at 318, the EPA determined that the available NO_X emissions reductions from non-EGU sources, for purposes of addressing good neighbor obligations for the 2008 ozone NAAQS, at a comparable cost threshold to the required EGU emissions reductions (for which EPA used an adjusted representative cost of $1,800 per ton), and based on the timing of when such measures could be implemented, did not provide a sufficiently meaningful and timely air quality improvement at the downwind receptors before those receptors were projected to resolve. *See* 86 FR 23110. On that basis, the EPA made a finding that emissions reductions from non-EGU sources were not required to eliminate significant contribution to downwind air quality problems under the interstate transport provision for the 2008 ozone NAAQS. In this proposal, EPA's ''significant contribution'' analysis at Step 3 of the 4-step framework includes a comprehensive evaluation of major stationary source non-EGU industries in the linked upwind states. The EPA is proposing to find that emissions from certain non-EGU sources in the upwind states significantly contribute to downwind air quality problems for the 2015 ozone NAAQS, and that cost-effective emissions reductions from these sources are required to eliminate significant contribution under the interstate transport provision. Therefore, this proposed rule includes required emissions reductions from non-EGU sources in upwind states to fulfill interstate transport obligations for the 2015 ozone NAAQS. This analysis is described fully in Section VI of the proposed rule.

In this proposed rule, the EPA also continues to apply its approach for assessing and avoiding ''over-control.'' In *EME Homer City,* the Supreme Court held that ''EPA cannot require a State to reduce its output of pollution by more than is necessary to achieve attainment in every downwind State or at odds with the one-percent threshold the Agency has set.'' 572 U.S. at 521. The Court acknowledged that ''instances of 'over-control' in particular downwind locations may be incidental to reductions necessary to ensure attainment elsewhere.'' *Id.* at 492.

> ''Because individual upwind States often 'contribute significantly' to nonattainment in multiple downwind locations, the emissions reductions required to bring one linked downwind State into attainment may well be large enough to push other linked downwind States over the attainment line. As the Good Neighbor Provision seeks attainment in *every* downwind State, however, exceeding attainment in one State cannot rank as 'over-control' unless unnecessary to achieving attainment in *any* downwind State. Only reductions unnecessary to downwind attainment *anywhere* fall outside the Agency's statutory authority.''

Id. at 522 (footnotes excluded).

The Court further explained that ''while EPA has a statutory duty to avoid over-control, the Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind.'' *Id.* at 523. Therefore, in the CSAPR Update and Revised CSAPR Update, the EPA evaluated possible over-control by considering whether an upwind state is linked solely to downwind air quality problems that can be resolved at a lower cost threshold, or if upwind states would reduce their emissions at a lower cost threshold to the extent that they would no longer meet or exceed the 1 percent air quality contribution threshold. *See, e.g.,* 81 FR at 74551–52. *See also Wisconsin,* 938 F.3d at 325

[65] For simplicity, the EPA (and courts) at times will refer to the Step 3 analysis as determining ''significant contribution''; however, EPA's approach at Step 3 also implements the ''interference with maintenance'' prong of the good neighbor provision, by also addressing emissions that impact the maintenance receptors identified at Step 1. *See* 86 FR 23074 (''In effect, EPA's determination of what level of upwind contribution constitutes 'interference' with a maintenance receptor is the same determination as what constitutes 'significant contribution' for a nonattainment receptor. Nonetheless, this continues to give independent effect to prong 2 because the EPA applies a broader definition for identifying maintenance receptors, which accounts for the possibility of problems maintaining the NAAQS under realistic potential future conditions.'').

[66] *EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. 489 (2014).

(over-control must be proven through a '' 'particularized, as-applied challenge' '') (quoting *EME Homer City Generation,* 572 U.S. at 523–24). The EPA continues to apply this framework for assessing over-control in this proposed rule, and, as discussed in Section VI.D.4 of this proposed rule, does not find any over-control at the proposed stringency to be sufficiently certain to warrant a relaxation in requirements for the sources in any covered state.

This evaluation of cost, NO_X reductions, and air quality improvements, including consideration of whether there is proven over-control, results in EPA's determination of the appropriate level of upwind control stringency that would result in elimination of emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind areas.

d. Step 4 Approach

The EPA proposes an approach similar to its prior transport rulemakings to implement the necessary emissions reductions through permanent and enforceable measures. The EPA proposes to require EGU sources to participate in an emissions trading program and proposes additional enhancements to the trading regime to maintain the selected control stringency over time and improve emissions performance at individual units, offering a necessary measure of assurance that emissions controls will be operated throughout the ozone season. For non-EGUs, the EPA proposes permanent and enforceable emissions rate limits and work practice standards, and associated compliance requirements, on several types of NO_X-emitting combustion units across several industrial sectors. The measures for both EGUs and non-EGUs are proposed to be required throughout the May 1–September 30 ozone season annually. The EGU program will begin with the 2023 ozone season, and non-EGU implementation will begin with the 2026 ozone season. Refer to Section VII.A of this proposed rule for details on the implementation schedule.

Based on the EPA's experience in implementing prior transport rulemakings, the Agency is proposing several enhancements to its trading-program approach for implementing good neighbor requirements for EGUs. In CSAPR, the CSAPR Update, and the Revised CSAPR Update, the EPA established interstate trading programs for EGUs to implement the necessary emissions reductions. In each of these rules, EGUs in each covered state are assigned an emissions budget for their collective emissions. Emissions allowances are allocated to units covered by the trading program, and the covered units then surrender allowances after the close of each control period, usually in an amount equal to their ozone season EGU NO_X emissions. While these programs have been effective in achieving overall reductions in emissions, experience has shown that these programs may not fully reflect in perpetuity the degree of emissions stringency determined necessary to eliminate significant contribution in Step 3 and may not adequately ensure the control of emissions throughout all days of the ozone season. At the same time, the EPA continues to find that an interstate-trading program approach delivers substantial benefits at Step 4 in terms of affording an appropriate degree of compliance flexibility, certainty in emissions outcomes, data and performance transparency, and cost-effective achievement of a high degree of aggregate emissions reductions. As such, EPA proposes to retain an interstate trading program approach while proposing several enhancements to that approach.

Thus, in this rulemaking, the EPA is proposing to include budget-setting procedures in the regulations that will allow state emissions budgets for control periods in 2025 and later years to reflect more current data on the composition and utilization of the EGU fleet (*e.g.,* the 2025 budgets would reflect 2023 data, the 2026 budgets would reflect 2024 data, etc.). These enhancements would enable the trading program to better maintain over time the selected control stringency that was determined to be necessary to address states' good neighbor obligations with respect to the 2015 ozone NAAQS. In prior programs, where state emissions budgets were static across years rather than calibrated to yearly fleet changes, the EPA has observed instances of units idling their emission controls in the latter years of the program.

In the trading programs established for ozone season NO_X emissions under CSAPR, the CSAPR Update, and the Revised CSAPR Update, the EPA included assurance provisions to limit state emissions to levels below 121 percent of the state's budget by requiring additional allowance surrenders in the instance that emissions in the state exceed this level. This limit on the degree to which a state's emissions can exceed its budget is designed to allow for a certain level of year-to-year variability within power sector emissions to account for fluctuations in demand and EGU operations and is responsive to previous court decisions (see discussion in Section VII.B.4 of this proposed rule). In this action, the EPA again proposes to retain the existing assurance provisions that limit state emissions to levels below 121 percent of the state's budget by requiring additional allowance surrenders in the instance that emissions in the state exceed this level for the 2023 and 2024 control periods. For control periods in 2025 and later years, the EPA is proposing to maintain the same general approach, but with adjustments that account for actual operational conditions in each control period to determine the specific levels above which additional allowance surrenders would be required. In addition, EPA is also proposing several additional enhancements to the EGU trading program in this action, including routine recalibrations of the total amount of banked allowances, unit-specific backstop daily emissions rates for certain units, and unit-specific secondary emissions limitations for units that contribute to exceedances of the assurance levels, to ensure EGU emissions control operation and associated air quality improvements. Implementation of the proposed EGU emissions reductions using a CSAPR NO_X trading program is further described in Section VII.B of this proposed rule.

In this action, the EPA is also proposing to establish emissions limitations for the non-EGU industry sources listed in Table III.A–1. The EPA has the authority to require emissions limitations from stationary sources, as well as from other sources and emissions activities, under CAA section 110(a)(2)(D)(i)(I). The EPA proposes that requiring NO_X emissions reductions through emissions rate limits from certain non-EGU industry sources that the EPA found at Step 3 to be relatively impactful[67] on downwind air quality is an effective strategy for reducing regional ozone transport. Therefore, the EPA proposes NO_X emissions limitations and associated compliance requirements for non-EGU sources to ensure the elimination of significant contribution of ozone precursor emissions required under the interstate

[67] *Section III of the* Non-EGU Screening Assessment memorandum in the docket for this rulemaking describes EPA's approach to evaluating impacts on downwind air quality, considering estimated total, maximum, and average contributions from each industry and the total number of receptors with contributions from each industry.

transport provision for the 2015 ozone NAAQS.

Finally, the EPA proposes that the control measures determined to be required for the identified EGU and non-EGU sources apply to both existing units and any new, modified, or reconstructed units meeting the applicability criteria established in this proposal. This is consistent with EPA's transport actions dating back to the NO_X SIP Call and the NO_X Budget Trading Program. In all CSAPR EGU trading programs, for instance, new EGUs are subject to the program, and the EPA established provisions for the allocation of allowances to such units through ''new unit set asides.'' *See, e.g.,* 86 FR 23126. In the NO_X SIP Call, the EPA required that states cover new and existing units in the relevant source sectors through an enforceable cap or other emissions limitation. *See* 40 CFR 51.121(f). EPA's approach of including new units in the NO_X Budget Trading Program promulgated under EPA's CAA section 126 authority was upheld by the D.C. Circuit in *Appalachian Power* v. *EPA,* 249 F.3d 1032 (2001). The EPA explained in its action:

> Once EPA has determined that the emissions from the existing sources in an upwind State already make a significant contribution to one or more petitioning downwind States, any additional emissions from a new source in that upwind State would also constitute a portion of that significant contribution, unless the emissions from that new source are limited to the level of highly effective controls.

Id. at 1058 (quoting EPA 1999 RTC at 39). The court affirmed this approach: ''Indeed, it would be irrational to enable the EPA to make findings that a group of sources in an upwind state contribute to downwind nonattainment, but then preclude the EPA from regulating new sources that contribute to that same pollution.'' *Id.* at 1057–58. The EPA proposes to adopt the same approach in this action, because this reasoning is equally applicable to addressing interstate transport obligations under CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS.

2. FIP Authority for Each State Covered by the Proposed Rule

On October 1, 2015, the EPA promulgated a revision to the 2015 8-hour ozone NAAQS, lowering the level of both the primary and secondary standards to 0.070 parts per million (ppm).[68] These revisions of the NAAQS, in turn, established a 3-year deadline for states to provide SIP submissions addressing infrastructure requirements under CAA sections 110(a)(1) and 110(a)(2), including the good neighbor provision, by October 1, 2018. If the EPA makes a determination that a state failed to submit a SIP, or if EPA disapproves a SIP submission, then the EPA is obligated under CAA section 110(c) to promulgate a FIP for that state within 2 years. For a more detailed discussion of CAA section 110 authority and timelines, refer to Section III.C of this proposed rule.

The EPA is proposing this FIP action now to address twenty-six states' good neighbor obligations for the 2015 ozone NAAQS, but the EPA will not finalize this FIP action for any state unless and until it has issued a final finding of failure to submit or a final disapproval of that state's SIP submission. The EPA is not required to wait to propose a FIP until after the Agency proposes or finalizes a SIP disapproval or makes a finding of failure to submit.[69] CAA section 110(c) authorizes EPA to *promulgate* a FIP ''at any time within 2 years'' of a SIP disapproval or making a finding of failure to submit. Thus, the EPA may promulgate a FIP contemporaneously with or immediately following predicate final action on a SIP (or finding no SIP was submitted). In order to accomplish this, the EPA must necessarily be able to propose a FIP prior to taking final action to disapprove a SIP or make a finding of failure to submit. The Supreme Court recognized this in *EME Homer City* in holding that the EPA is not obligated to first define a state's good neighbor obligations or give the state an additional opportunity to submit an approvable SIP before promulgating a FIP: ''EPA is not obliged to wait two years or postpone its action even a single day: The Act empowers the Agency to promulgate a FIP 'at any time' within the two-year limit.'' [70] Furthermore, the D.C. Circuit in *Wisconsin* held that states and EPA are obligated to fully address good neighbor obligations for ozone ''as expeditiously as practical'' and in no event later than the next relevant downwind attainment dates found in CAA section 181(a).[71] In *Maryland* v. *EPA,* the D.C. Circuit made clear that *Wisconsin'*s and *North Carolina'*s holdings are fully applicable to the Marginal area attainment date for the 2015 ozone NAAQS,[72] which fell on August 3, 2021.[73] The *Wisconsin* court emphasized that EPA has the authority under CAA section 110 to structure and time its actions in a manner such that the Agency can ensure necessary reductions are achieved by the downwind attainment dates.[74]

On February 22, 2022, the EPA proposed to disapprove 19 good neighbor SIP submissions (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Ohio, Oklahoma, Tennessee, Texas, West Virginia, Wisconsin).[75] The EPA is proposing to

[68] *National Ambient Air Quality Standards for Ozone,* Final Rule, 80 FR 65292 (October 26, 2015). Although the level of the standard is specified in the units of ppm, ozone concentrations are also described in parts per billion (ppb). For example, 0.070 ppm is equivalent to 70 ppb.

[69] The EPA notes there are three consent decrees to resolve three deadline suits related to EPA's duty to act on good neighbor SIP submissions for the 2015 ozone NAAQS. In *New York et al.* v. *Regan, et al.* (No. 1:21–CV–00252, S.D.N.Y.), the EPA agreed to take final action on the 2015 ozone NAAQS good neighbor SIP submissions from Indiana, Kentucky, Michigan, Ohio, Texas, and West Virginia by April 30, 2022; however, if the EPA proposes to disapprove any SIP submissions and proposes a replacement FIP by February 28, 2022, then EPA's deadline to take final action on that SIP submission is extended to December 30, 2022. In *Downwinders at Risk et al.* v. *Regan* (No. 21–cv–03551, N.D. Cal.), the EPA agreed to take final action on the 2015 ozone NAAQS good neighbor SIP submissions from Alabama, Arkansas, Connecticut, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Tennessee, Texas, West Virginia, and Wisconsin by April 30, 2022; however, if the EPA proposes to disapprove any of these SIP submissions and proposes a replacement FIP by February 28, 2022, then EPA's deadline to take final action on that SIP submission is December 30, 2022. In this CD, the EPA also agreed to take final action on Hawaii's SIP submission by April 30, 2022, and to take final action on the SIP submissions of Arizona, California, Montana, Nevada, and Wyoming by December 15, 2022. In *Our Children's Earth Foundation* v. *EPA* (No. 20–8232, S.D.N.Y.), the EPA agreed to take final action on the 2015 ozone NAAQS good neighbor SIP submission from New York by April 30, 2022; however, if the EPA proposes to disapprove New York's SIP submission and proposes a replacement FIP by February 28, 2022, then EPA's deadline to take final action on New York's SIP submission is extended to December 30, 2022.

[70] *See EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. 489, 509 (2014) (citations omitted).

[71] *Wisconsin* v. *EPA,* 938 F.3d 303, 313–14 (D.C. Cir. 2019) (citing *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir. 2008).

[72] *Maryland* v. *EPA,* 958 F.3d 1185, 1203–04 (D.C. Cir. 2020).

[73] *See* CAA section 181(a); 40 CFR 51.1303; *Additional Air Quality Designations for the 2015 Ozone National Ambient Air Quality Standards,* 83 FR 25776 (June 4, 2018, effective August 3, 2018).

[74] 938 F.3d at 318 (''When EPA determines a State's SIP is inadequate, EPA presumably must issue a FIP that will bring that State into compliance before upcoming attainment deadlines, even if the outer limit of the statutory timeframe gives EPA more time to formulate the FIP.'') (citing *Sierra Club* v. *EPA,* 294 F.3d 155, 161 (D.C. Cir. 2002)).

[75] *See* 87 FR 9463 (Maryland); 87 FR 9484 (New Jersey, New York); 87 FR 9498 (Kentucky); 87 FR 9516 (West Virginia); 87 FR 9533 (Missouri); 87 FR 9545 (Alabama, Mississippi, Tennessee); 87 FR 9798 (Arkansas, Louisiana, Oklahoma, Texas); 87 FR 9838 (Illinois, Indiana, Michigan, Minnesota,

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promulgate 2015 ozone NAAQS good neighbor FIPs for these same states, as well as California, Nevada, and Wyoming, but will not finalize a FIP for any of these states unless and until the EPA formally finalizes disapprovals of their SIP submittals or, in the event that any of these states withdraw their good neighbor SIP submissions after this proposal, makes a finding of failure to submit.[76] *See* CAA section 110(c).

Additionally, the EPA has taken action that has triggered EPA's obligation under CAA section 110(c) to promulgate FIPs addressing the good neighbor provision for some other states. On December 5, 2019, the EPA published a rule finding that seven states (Maine, New Mexico, Pennsylvania, Rhode Island, South Dakota, Utah, and Virginia) failed to submit or otherwise make complete submissions that address the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS.[77] This finding triggered a 2-year deadline for the EPA to issue FIPs to address the good neighbor provision for these states by January 6, 2022. As the EPA has subsequently received and taken final action to approve good neighbor SIPs from Maine, Rhode Island, and South Dakota,[78] the EPA currently has authority under the December 5, 2019, finding of failure to submit to issue FIPs for New Mexico, Pennsylvania, Utah, and Virginia. In this proposal, EPA is issuing proposed FIP requirements for Pennsylvania, Utah, and Virginia.[79]

C. Other CAA Authorities for This Action

1. Correction of EPA's Determination Regarding Delaware's SIP Submission and Its Impact on EPA's FIP Authority for Delaware

In 2020, the EPA approved an infrastructure SIP submission from Delaware for the 2015 ozone NAAQS, which in part addressed the good neighbor provision at CAA section 110(a)(2)(D)(i)(I).[80] The EPA concluded that, based on the modeling results presented in a 2018 March memorandum and using a 2023 analytic year, Delaware's largest impact on any potential downwind nonattainment or maintenance receptor was less than 1 percent of the NAAQS.[81] As a result, the EPA found that Delaware would not significantly contribute to nonattainment or interfere with maintenance in any other state.[82] Therefore, the EPA approved the portion of Delaware's infrastructure SIP that addressed CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS.

Subsequent to the release of the modeling data shared in the March 2018 memorandum and EPA's approval of Delaware's 2015 ozone NAAQS good neighbor SIP submission, the EPA performed updated modeling, as described in Section V of this proposed rule. The data from this updated air quality modeling now show that Delaware is projected to contribute more than 1 percent of the NAAQS to downwind receptors in Bristol, Pennsylvania, in the 2023 analytic year.[83] Therefore, in light of the modeling data, EPA is proposing to find that its approval of Delaware's 2015 ozone NAAQS infrastructure SIP submission, with regard only to the portion addressing the good neighbor provision at CAA section 110(a)(2)(D)(i)(I), was in error. Section 110(k)(6) of the CAA gives the Administrator authority, without any further submission from a state, to revise certain prior actions, including actions to approve SIPs, upon determining that those actions were in error.[84] The modeling data demonstrate that EPA's prior conclusion that Delaware will not significantly contribute to nonattainment or interfere with maintenance in any other state in the 2023 analytic year was incorrect, which means that EPA's approval of Delaware's good neighbor SIP submission was in error.

Therefore, the EPA proposes to correct the error in Delaware's good neighbor SIP approval. This error correction under CAA section 110(k)(6) would revise the approval of the portion of Delaware's 2015 ozone NAAQS infrastructure SIP that addresses CAA section 110(a)(2)(D)(i)(I) to a disapproval and rescind any statements that the portion of Delaware's infrastructure SIP submission that addresses CAA section 110(a)(2)(D)(i)(I) satisfies the requirements of the good neighbor provision. The EPA is not proposing to correct the elements of Delaware's 2015 ozone NAAQS infrastructure SIP that do not address CAA section 110(a)(2)(D)(i)(I).

As discussed in greater detail in the sections that follow, the EPA is proposing to determine that there are additional emissions reductions that are required for Delaware to satisfy its good neighbor obligations for the 2015 ozone NAAQS. The analysis on which the EPA proposes this conclusion for Delaware is the same, regionally consistent analytical framework on which the Agency proposes FIP action for the other states included in this proposal. The Agency recognizes that it is possible, based on updated information for the final rule—as applied within a regionally consistent analytical framework—that Delaware (or other states for which the EPA proposes FIPs in this action) may be found to have no further interstate transport obligation for the 2015 ozone NAAQS. If such a circumstance were to occur, the EPA anticipates that it would not finalize this proposed error correction or may modify the error correction such that the approval of Delaware's portion of the SIP as it relates to its good neighbor obligations may be affirmed.

Ohio, Wisconsin). EPA has not yet proposed action on interstate transport SIPs submitted by California, Nevada, Utah, and Wyoming.

[76] See the document titled ''Status of CAA Section 110(a)(2)(D)(i)(I) SIP Submissions for the 2015 Ozone NAAQS for States Covered by the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards,'' included in the docket for this rulemaking, for additional information on EPA's statutory authorities for this proposed rule.

[77] *Findings of Failure To Submit a Clean Air Act Section 110 State Implementation Plan for Interstate Transport for the 2015 Ozone National Ambient Air Quality Standards (NAAQS),* 84 FR 66612 (December 5, 2019, effective January 6, 2020).

[78] *Air Plan Approval; Maine and New Hampshire; 2015 Ozone NAAQS Interstate Transport Requirements,* 86 FR 45870 (August 17, 2021); *Air Plan Approval; Rhode Island; 2015 Ozone NAAQS Interstate Transport Requirements,* 86 FR 70409 (December 10, 2021); *Promulgation of State Implementation Plan Revisions; Infrastructure Requirements for the 2015 Ozone National Ambient Air Quality Standards; South Dakota; Revisions to the Administrative Rules of South Dakota,* 85 FR 29882 (May 19, 2020).

[79] The EPA has not yet taken action on a subsequent good neighbor SIP submission from New Mexico or Utah; EPA is not including New Mexico in this proposed action.

[80] *Approval and Promulgation of Air Quality Implementation Plans; Delaware; Infrastructure Requirements for the 2015 Ozone Standard and Revisions to Modeling Requirements,* 85 FR 25307 (May 1, 2020).

[81] ''Technical Support Document for the Delaware State Implementation Plan for the Infrastructure Requirements for the 2015 Ozone Standard and Revisions to Modeling Requirements'' at 16, available in Docket No. EPA–R03–OAR–2019–0663.

[82] *Id.* at 17. Based on the 2023 modeling from the 2018 memorandum, Delaware was expected in 2023 to have a 0.40 ppb impact on a potential nonattainment receptor in Fairfield, Connecticut (Site ID 90019003) and a 0.38 ppb impact at a potential maintenance receptor in Queens, New York (Site ID 360810124).

[83] The contribution from Delaware in 2023 to the receptor in Bristol, Pennsylvania, is 1.36 ppb.

[84] *See, e.g.,* 86 FR 23054, 23068 (error correcting prior approval of Kentucky's transport SIP submission for the 2008 ozone NAAQS to a disapproval and simultaneously promulgating FIP on the basis of the *Wisconsin* and *New York* decisions remanding CSAPR Update and vacating CSAPR Close-Out and new information establishing Kentucky was linked to downwind receptors).

2. Application of Rule in Indian Country and Necessary or Appropriate Finding

The EPA proposes that this rule will be applicable in all areas of Indian country (as defined at 18 U.S.C. 1151) within the covered geography of the proposal, as defined below. Currently, certain areas of Indian country within the geography of the proposal are subject to state implementation planning authority. Other areas of Indian country within that geography would be subject to tribal planning authority, although none of the relevant tribes have as yet sought eligibility to administer a tribal plan to implement the good neighbor provision.[85] As described later, the EPA is proposing to include all areas of Indian country within the covered geography, notwithstanding whether those areas are currently subject to a state's implementation planning authority or the potential planning authority of a tribe.

With respect to areas of Indian country not currently subject to a state's implementation planning authority—*i.e.,* Indian reservation lands (with the partial exception of reservation lands located in the State of Oklahoma, as described further below) and other areas of Indian country over which the EPA or a tribe has demonstrated that a tribe has jurisdiction—the EPA here proposes a ''necessary or appropriate'' finding that direct federal implementation of the rule's requirements is warranted under CAA section 301(d)(4) and 40 CFR 49.11(a) (the areas of Indian country subject to this finding are referred to later as the 301(d) FIP areas). Indian Tribes may, but are not required to, submit tribal plans to implement CAA requirements, including the good neighbor provision. Section 301(d) of the CAA and 40 CFR part 49 authorize the Administrator to treat an Indian Tribe in the same manner as a state (*i.e.,* TAS) for purposes of developing and implementing a tribal plan implementing good neighbor obligations. *See* 40 CFR 49.3; *see also* ''Indian Tribes: Air Quality Planning and Management,'' hereafter ''Tribal Authority Rule,'' (63 FR 7254, February 12, 1998). The EPA is authorized to directly implement the good neighbor provision in the 301(d) FIP areas when it finds, consistent with the authority of CAA section 301—which the EPA has exercised in 40 CFR 49.11—that it is necessary or appropriate to do so.[86]

The EPA proposes in this action to find that it is both necessary and appropriate to regulate all new and existing EGU and non-EGU sources meeting the applicability criteria set forth in this proposed rule in all of the 301(d) FIP areas that are located within the geographic scope of coverage of the rule. For purposes of this proposed finding, the geographic scope of coverage of the rule means the areas of the United States encompassed within the borders of the states EPA has determined to be linked at Steps 1 and 2 of the 4-step interstate transport framework.[87] For EGU applicability criteria, *see* Section VII.B of this proposed rule; for non-EGU applicability criteria, *see* Section VII.C of this proposed rule. To EPA's knowledge, only one existing EGU or non-EGU source is located within the 301(d) FIP areas: The Bonanza Power Plant, an EGU source, located on the Uintah and Ouray Reservation, geographically located within the borders of Utah.

This proposed finding is consistent with EPA's prior good neighbor rules. In prior rulemakings under the good neighbor provision, the EPA has included all areas of Indian country within the geographic scope of those FIPs, such that any new or existing sources meeting the rules' applicability criteria would be subject to the rule irrespective of whether subject to state or tribal underlying CAA planning authority. In CSAPR, the CSAPR Update, and the Revised CSAPR Update, the scope of the emissions trading programs established for EGUs extended to cover all areas of Indian country located within the geographic boundaries of the covered states. In these rules, at the time of their promulgation, no existing units were located in the covered areas of Indian country; under the general applicability criteria of the trading programs, however, any new sources locating in such areas would become subject to the programs. Thus, EPA established a separate allowance allocation that would be available for any new units locating in any of the relevant areas of Indian country. *See, e.g.,* 76 FR at 48293 (describing the CSAPR methodology of allowance allocation under the ''Indian country new unit set-aside'' provisions); *see also id.* at 48217 (explaining EPA's source of authority for directly regulating in relevant areas of Indian country as necessary or appropriate). Further, in any action in which the EPA subsequently approved a state's SIP submittal to partially or wholly replace the provisions of a CSAPR FIP, EPA has clearly delineated that it will continue to administer the Indian country new unit set aside for sources in any areas of Indian country geographically located within a state's borders and not subject to that state's CAA planning authority, and the state may not exercise jurisdiction over any such sources. *See, e.g.,* 82 FR 46674, 46677 (October 6. 2017) (approving Alabama's SIP submission establishing a state CSAPR trading program for ozone season NO_X, but providing, ''The SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian tribe has demonstrated that a tribe has jurisdiction.'').

In this proposed rule, the EPA proposes to take an approach similar to the prior CSAPR rulemakings with respect to regulating sources in the 301(d) FIP areas.[88] The EPA believes this approach is necessary and appropriate for several reasons. First, the purpose of this rule is to address the

[85] We note that, consistent with EPA's prior good neighbor actions in California, the regulatory ozone monitor located on the Morongo Band of Mission Indians (''Morongo'') reservation is a projected downwind receptor in 2023. *See* monitoring site 060651016 in Table V.D–1. We also note that the Temecula, California regulatory ozone monitor is a projected downwind receptor in 2023 and in past regulatory actions has been deemed representative of air quality on the Pechanga Band of Luiseño Indians (''Pechanga'') reservation. *See, e.g., Approval of Tribal Implementation Plan and Designation of Air Quality Planning Area; Pechanga Band of Luiseño Mission Indians,* 80 FR 18120, at 18121–18123 (April 3, 2015); *see also* monitoring site 060650016 in Table V.D–1. The presence of receptors on, or representative of, the Morongo and Pechanga reservations does not trigger obligations for the Morongo and Pechanga Tribes. Nevertheless, these receptors are relevant to EPA's assessment of any linked upwind states' good neighbor obligations. *See, e.g., Approval and Promulgation of Air Quality State Implementation Plans; California; Interstate Transport Requirements for Ozone, Fine Particulate Matter, and Sulfur Dioxide,* 83 FR 65093 (December 19, 2018). Under 40 CFR 49.4(a), tribes are not subject to the specific plan submittal and implementation deadlines for NAAQS-related requirements, including deadlines for submittal of plans addressing transport impacts.

[86] *See Arizona Pub. Serv. Co.* v. *U.S. E.P.A.,* 562 F.3d 1116, 1125 (10th Cir. 2009) (stating that 40 CFR 49.11(a) ''provides the EPA discretion to determine what rulemaking is necessary or appropriate to protect air quality and requires the EPA to promulgate such rulemaking''); *Safe Air For Everyone* v. *U.S. Env't Prot. Agency,* No. 05–73383, 2006 WL 3697684, at *1 (9th Cir., Dec. 15, 2006) (''The statutes and regulations that enable EPA to regulate air quality on Indian reservations provide EPA with broad discretion in setting the content of such regulations.'').

[87] With respect to any non-EGU sources located in the 301(d) FIP areas, the geographic scope of coverage of this proposed rule does not include those states for which EPA proposes to find, based on air quality modeling, that no further linkage exists by the 2026 analytic year at Steps 1 and 2. The states no longer projected to be linked in 2026 are Alabama, Delaware, and Tennessee.

[88] *See* Section VII.B.9 of this action for a discussion of revisions that are proposed in this rulemaking regarding the point in the allowance allocation process at which the EPA would establish set-asides of allowances for units in Indian country not subject to a state's CAA implementation planning authority.

interstate transport of ozone on a national scale, and the technical record establishes that the nonattainment and maintenance receptors located throughout the country are impacted by sources of ozone pollution on a broad geographic scale. The upwind regions associated with each receptor typically span at least two, and often far more, states. Within the broad upwind region covered by this proposal, the EPA proposes to apply—consistent with the methodology of allocating upwind responsibility in prior transport rules going back to the NO_X SIP Call—a uniform level of control stringency. (*See* Section VI of this proposed rule for a discussion of EPA's determination of control stringency for this proposal.) Within this approach, consistency in rule requirements across all jurisdictions is vital in ensuring the remedy for ozone transport is, in the words of the Supreme Court, ''efficient and equitable,'' 572 U.S. 489, 519. In particular, as the Supreme Court found in *EME Homer City Generation,* allocating responsibility through uniform levels of control across the entire upwind geography is ''equitable'' because, by imposing uniform cost thresholds on regulated States, EPA's rule subjects to stricter regulation those States that have done relatively less in the past to control their pollution. Upwind States that have not yet implemented pollution controls of the same stringency as their neighbors will be stopped from free riding on their neighbors' efforts to reduce pollution. They will have to bring down their emissions by installing devices of the kind in which neighboring States have already invested. *Id.*

In the context of addressing regional-scale ozone transport in this proposal, a uniform level of stringency that extends to and includes the 301(d) FIP areas geographically located within the boundaries of the linked upwind states carries significant force. Failure to include all such areas within the scope of the rule creates a significant risk that these areas may be targeted for the siting of facilities emitting ozone-precursor pollutants, in order to avoid the regulatory costs that would be imposed under this proposed rule in the surrounding areas of state jurisdiction. Electricity generation or the production of other goods and commodities may become more cost-competitive at any EGUs or non-EGUs not subject to the rule but located in a geography where all surrounding facilities in the same industrial category are subject to the rule. For instance, the affected EGU source located on the Uintah and Ouray Reservation of the Ute Tribe is in an area that is interconnected with the western electricity grid and is owned and operated by an entity that generates and provides electricity to customers in several states. It is both necessary and appropriate, in EPA's view, to avoid creating, via this proposed rule, a structure of incentives that may cause generation or production—and the associated NO_X emissions—to shift into the 301(d) FIP areas to escape regulation needed to eliminate interstate transport under the good neighbor provision.

The EPA believes it is appropriate to propose direct federal implementation of the proposed rule's requirements in the 301(d) FIP areas at this time rather than at a later date. Tribes have the opportunity to seek TAS and to undertake tribal implementation plans under the CAA. To date, the one tribe which could develop and seek approval of a tribal implementation plan to address good neighbor obligations with respect to an existing EGU in the 301(d) FIP areas for the 2015 ozone NAAQS (or for any other NAAQS), the Ute Indian Tribe of the Uintah and Ouray Reservation, has not expressed an intent to do so. Nor has the EPA heard such intentions from any other tribe, and it would not be reasonable to expect tribes to undertake that planning effort, particularly when no existing sources are currently located on their lands. Further, the EPA is mindful that under court precedent, the EPA and states generally bear an obligation to fully implement any required emissions reductions to eliminate significant contribution under the good neighbor provision as expeditiously as practicable and in alignment with downwind areas' attainment schedule under the Act. As discussed in Section VII.A of this proposed rule, the EPA anticipates implementing certain required emissions reductions by the 2023 ozone season, the last full ozone season before the 2024 Moderate area attainment date, and other key additional required emissions reductions by the 2026 ozone season, the last full ozone season before the 2027 Serious area attainment date. Absent this proposed federal implementation plan in the 301(d) FIP areas, NO_X emissions from any existing or new EGU or non-EGU sources located in, or locating in, the 301(d) FIP areas within the covered geography of the rule would remain unregulated and could potentially increase. This would be inconsistent with EPA's overall goal of aligning good neighbor obligations with the downwind areas' attainment schedule and to achieve emissions reductions as expeditiously as practicable.

Further, the EPA recognizes that Indian country, including the 301(d) FIP areas, is often home to communities with environmental justice concerns, and these communities may bear a disproportionate level of pollution burden as compared with other areas of the United States. EPA's draft Strategic Plan for Fiscal Year 2022–2026 [89] includes an objective to promote environmental justice at the Federal, Tribal, state, and local levels and states: ''Integration of environmental justice principles into all EPA activities with Tribal governments and in Indian country is designed to be flexible enough to accommodate EPA's Tribal program activities and goals, while at the same time meeting the Agency's environmental justice goals.'' By including all areas of Indian country within the covered geography of the rule, the EPA is advancing environmental justice, lowering pollution burdens in such areas, and preventing the potential for ''pollution havens'' to form in such areas as a result of facilities seeking to locate there to avoid the requirements that would otherwise apply outside of such areas under this proposed rule.

Therefore, in order to ensure timely alignment of all needed emissions reductions with the larger timetable of this proposed rule, to ensure equitable distribution of the upwind pollution reduction obligation across all upwind jurisdictions, to avoid perverse economic incentives to locate sources of ozone-precursor pollution in the 301(d) FIP areas, and to deliver greater environmental justice to tribal communities in line with Executive Order 13985: Advancing Racial Equity and Support for Underserved Communities Through the Federal Government,[90] EPA proposes to find it both necessary and appropriate that all existing and new EGU and non-EGU sources that are located in the 301(d) FIP areas within the geographic boundaries of the covered states, and which would be subject to this rule if located within areas subject to state CAA planning authority, should be included in this rule. The EPA proposes this finding under section 301(d)(4) of the Act and 40 CFR 49.11. Further, in order to avoid ''unreasonable delay'' in

[89] *https://www.epa.gov/system/files/documents/2021-10/fy-2022-2026-epa-draft-strategic-plan.pdf*

[90] Executive Order 13985 (January 20, 2021): *https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/20/executiveorder-advancing-racial-equity-and-support-for-underserved-communities-through-the-federal-government/.*

promulgating this FIP, as required under section 49.11, the EPA believes it is appropriate to make this proposed finding now, in order to align emissions reduction obligations for any covered new or existing sources in the 301(d) FIP areas with the larger schedule of reductions under this proposed rule. Because all other covered EGU and non-EGU sources within the geography of this proposed rule would be subject to emissions reductions of uniform stringency beginning in the 2023 ozone season, and as necessary to fully and expeditiously address good neighbor obligations for the 2015 ozone NAAQS, there is little benefit to be had by not proposing to include the 301(d) FIP areas in this rule now and a potentially significant downside to not doing so.

The Agency recognizes that Tribal governments may still choose to seek TAS to develop a Tribal plan with respect to the obligations under this proposed rule, and this proposed determination does not preclude the tribes from taking such actions. The EPA will continue to consult with the government of the Ute Indian Tribe of the Uintah and Ouray Reservation, and any other tribe wishing to continue consultation, during the comment period for this proposal. The EPA invites comment on this proposed finding.

a. Indian Country Subject to State Implementation Planning Authority

Following the U.S. Supreme Court decision in *McGirt* v. *Oklahoma,* 140 S. Ct. 2452 (2020), the Governor of the State of Oklahoma requested approval under Section 10211(a) of the Safe, Accountable, Flexible, Efficient Transportation Equity Act of 2005: A Legacy for Users, Public Law 109–59, 119 Stat. 1144, 1937 (August 10, 2005) (''SAFETEA''), to administer in certain areas of Indian country (as defined at 18 U.S.C. 1151) the State's environmental regulatory programs that were previously approved by the EPA for areas outside of Indian country. The State's request excluded certain areas of Indian country further described later. In addition, the State only sought approval to the extent that such approval is necessary for the State to administer a program in light of *Oklahoma Dept. of Environmental Quality* v. *EPA,* 740 F.3d 185 (D.C. Cir. 2014).[91]

On October 1, 2020, the EPA approved Oklahoma's SAFETEA request to administer all the State's EPA-approved environmental regulatory programs, including the Oklahoma SIP, in the requested areas of Indian country.[92] As requested by Oklahoma, the EPA's approval under SAFETEA does not include Indian country lands, including rights-of-way running through the same, that: (1) Qualify as Indian allotments, the Indian titles to which have not been extinguished, under 18 U.S.C. 1151(c); (2) are held in trust by the United States on behalf of an individual Indian or Tribe; or (3) are owned in fee by a Tribe, if the Tribe (a) acquired that fee title to such land, or an area that included such land, in accordance with a treaty with the United States to which such Tribe was a party, and (b) never allotted the land to a member or citizen of the Tribe (collectively ''excluded Indian country lands'').

EPA's approval under SAFETEA expressly provided that to the extent EPA's prior approvals of Oklahoma's environmental programs excluded Indian country, any such exclusions are superseded for the geographic areas of Indian country covered by EPA's approval of Oklahoma's SAFETEA request.[93] The approval also provided that future revisions or amendments to Oklahoma's approved environmental regulatory programs would extend to the covered areas of Indian country (without any further need for additional requests under SAFETEA).

In a **Federal Register** notice published on February 22, 2022 (87 FR 9798), the EPA proposed to disapprove the portion of an Oklahoma SIP submittal pertaining to the state's interstate transport obligations under CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS. Consistent with the D.C. Circuit's decision in *ODEQ* v. *EPA* and with EPA's October 1, 2020 SAFETEA approval, if this disapproval is finalized as proposed, EPA will have authority under CAA section 110(c) to promulgate a FIP as needed to address the disapproved aspects of the State's good neighbor SIP submittal.[94] In accordance with the discussion above, EPA's FIP authority in this circumstance would extend to all Indian country in Oklahoma, other than the excluded Indian country lands, as described previously.[95] Because—per the State's request under SAFETEA—EPA's October 1, 2020 approval does not displace any SIP authority previously exercised by the State under the CAA as interpreted in *ODEQ* v. *EPA,* EPA's FIP authority under CAA section 110(c) would also apply to any Indian allotments or dependent Indian communities located outside of an Indian reservation over which there has been no demonstration of tribal authority. EPA's FIP authority under CAA section 110(c) would similarly apply to Indian allotments or dependent Indian communities located outside of an Indian reservation over which there has been no demonstration of tribal authority located in any other state within the geographic scope of this proposed rule.

In light of the relevant legal authorities discussed above regarding the scope of the State of Oklahoma's regulatory jurisdiction under the CAA, the EPA has FIP authority under CAA section 110(c) with respect to all Indian country in Oklahoma other than excluded Indian country lands. To the extent any change occurs in the scope of Oklahoma's SIP authority in Indian country before the finalization of this proposed rule, such a change may affect the ability of the Agency to exercise the FIP authority provided under section 110(c) of the Act.[96] In that eventuality,

[91] In *ODEQ* v. *EPA,* the D.C. Circuit held that under the CAA, a state has the authority to implement a SIP in non-reservation areas of Indian country in the state, where there has been no demonstration of tribal jurisdiction. Under the D.C. Circuit's decision, the CAA does not provide authority to states to implement SIPs in Indian reservations. *ODEQ* did not, however, substantively address the separate authority in Indian country provided specifically to Oklahoma under SAFETEA. That separate authority was not invoked until the State submitted its request under SAFETEA, and was not approved until EPA's decision, described in this section, on October 1, 2020.

[92] Available in the docket for this rulemaking.

[93] EPA's prior approvals relating to Oklahoma's SIP frequently noted that the SIP was not approved to apply in areas of Indian country (consistent with the D.C. Circuit's decision in *ODEQ* v. *EPA*) located in the state. *See, e.g.,* 85 FR 20178, 20180 (April 10, 2020). Such prior expressed limitations are superseded by EPA's approval of Oklahoma's SAFETEA request.

[94] The antecedent fact that the state had the authority and jurisdiction to implement requirements under the good neighbor provision, in EPA's view, supplies the condition necessary for the Agency to exercise its FIP authority to the extent the EPA has disapproved the state's SIP submission with respect to those requirements. Under CAA section 110(c), the EPA ''stands in the shoes of the defaulting state, and all of the rights and duties that would otherwise fall to the state accrue instead to the EPA.'' *Central Ariz. Water Conservation Dist.* v. *EPA,* 990 F.2d 1531, 1541 (9th Cir. 1993).

[95] With respect to those areas of Indian country constituting ''excluded Indian country lands'' in the State of Oklahoma, as defined above, the EPA proposes to apply the same necessary or appropriate finding as set forth above with respect to all other 301(d) FIP areas within the geographic scope of coverage of the rule.

[96] On December 22, 2021, the EPA proposed to withdraw and reconsider the October 1, 2020, SAFETEA approval. *See https://www.epa.gov/ok/proposed-withdrawal-and-reconsideration-and-supporting-information.* The EPA is engaging in further consultation with tribal governments and expects to have discussions with the State of Oklahoma as part of this reconsideration. The EPA also notes that the October 1, 2020, approval is the

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and to the extent any such areas would then fall more appropriately within the 301(d) FIP areas as described earlier in this section, EPA's proposed necessary or appropriate finding as set forth above with respect to all other 301(d) FIP areas within the geographic scope of coverage of the rule would then apply.

V. Analyzing Downwind Air Quality Problems and Contributions From Upwind States

A. Selection of Analytic Years for Evaluating Ozone Transport Contributions to Downwind Air Quality Problems

In this section, the EPA describes its process for selecting analytic years for air quality modeling and analyses performed to identify nonattainment and maintenance receptors and identify upwind state linkages. For this proposed rule, the EPA evaluated air quality to identify receptors at Step 1 for three analytic years: 2023, 2026, and 2032. The EPA evaluated interstate contributions to these receptors from individual upwind states at Step 2 for two of these analytic years: 2023 and 2026. In selecting these years, the EPA views 2023 and 2026, in particular, to constitute years by which key emissions reductions from EGUs and non-EGUS can be implemented ''as expeditiously as practicable.'' (The EPA explains in detail in Section VII of this proposed rule its proposed determination that the necessary emissions reductions cannot be achieved any more quickly.) In addition, these years are the last full ozone seasons before the Moderate and Serious area attainment dates for the 2015 ozone NAAQS (ozone seasons run each year from May 1–September 30). In order to demonstrate attainment by these deadlines, downwind states would be required to rely on design values calculated using ozone design values from 2021 through 2023 and 2024 through 2026, respectively. By focusing its analysis, and, potentially, achieving emissions reductions by, the last full ozone seasons before the attainment dates (*i.e.,* in 2023 or 2026), this proposed rule, if finalized, can assist the downwind areas with demonstrating attainment or receiving extensions of attainment dates under CAA section 181(a)(5).

It would not make sense for the EPA to analyze any earlier year than 2023. EPA continues to interpret the good neighbor provision as forward-looking, based on Congress's use of the future-tense ''will'' in section 110(a)(2)(D)(i), an interpretation upheld in *Wisconsin,* 938 F.3d at 322. It would be ''anomalous,'' *id.,* for the EPA to impose good neighbor obligations in 2023 and future years based solely on finding that ''significant contribution'' had existed at some time in the past. *Id.*

Applying this framework in this proposal, the EPA recognizes that the 2021 Marginal area attainment date has already passed. Further, based on the timing of this proposal, it will not be possible to finalize this rulemaking before the 2022 ozone season has also passed. Thus, EPA has selected 2023 as the first appropriate future analytic year for this proposed rule because it reflects implementation of good neighbor obligations as expeditiously as practicable and coincides with the August 3, 2024, Moderate area attainment date established for the 2015 ozone NAAQS.

The EPA conducted additional analysis for the 2026 and 2032 analytic years in order to ensure a complete Step 3 analysis for future ozone transport contributions to downwind areas. These years also coincide with the last full ozone seasons before future attainment dates for the 2015 ozone NAAQS, and 2026 coincides with the ozone season by which key additional emissions reductions from EGUs and non-EGUs become available. Thus, the EPA analyzed additional years beyond 2023 to determine whether any additional emissions reductions that are impossible to obtain by the 2024 attainment date could still be necessary in order to fully address significant contribution, taking into account the 2027 Serious area attainment date and the 2033 Severe area attainment date for the 2015 ozone NAAQS. In all cases, the proposed implementation of necessary emissions reductions is as expeditiously as practicable, with all possible emissions reductions implemented by the next applicable attainment date.

The timing framework and selection of analytic years set forth above comports with the D.C. Circuit's direction in *Wisconsin* that implementing good neighbor obligations beyond the dates established for attainment may be justified on a proper showing of impossibility or necessity. *See* 938 F.3d at 320.

The remainder of this section includes information on (1) the air quality modeling platform used in support of the proposed rule with a focus on the base year and future year base case emissions inventories, (2) the method for projecting design values in 2023, 2026, and 2032, and (3) the approach for calculating ozone contributions from upwind states. The Agency also provides the design values for nonattainment and maintenance receptors and the predicted interstate contributions that are at or above the 1 percent of the NAAQS screening threshold. The 2016 base period and 2023, 2026, and 2032 future design values and contributions for all ozone monitoring sites are provided in the docket for this proposed rule. The Air Quality Modeling Technical Support Document (AQM TSD) in the docket for this proposed rule contains more detailed information on the air quality modeling aspects of this rule.

B. Overview of Air Quality Modeling Platform

The EPA used version 2 of the 2016-based modeling platform for the air quality modeling for this proposed rule. This modeling platform includes 2016 base year emissions from anthropogenic and natural sources and 2016 meteorology. The platform also includes anthropogenic emissions projections for 2023, 2026, and 2032. The emissions data contained in this platform represent an update to the 2016 version 1 inventories that were developed by the EPA, the Multi-Jurisdictional Organizations (MJOs), and state and local air agencies as part of the Emissions Inventory Collaborative Process.

The air quality modeling for this proposal was performed for a modeling region (*i.e.,* modeling domain) that covers the contiguous 48 states using a horizontal resolution of 12 x 12 km. The EPA used the CAMx version 7.10 for air quality modeling since this was the most recent version of CAMx available at the time the air quality modeling was performed.[97] Additional information on the 2016-based air quality modeling platform can be found in the AQM TSD.

C. Emissions Inventories

The EPA developed emissions inventories for this proposal, including emissions estimates for EGUs, non-EGU point sources, stationary nonpoint sources, onroad mobile sources, nonroad mobile sources, other mobile sources, wildfires, prescribed fires, and biogenic emissions that are not the direct result of human activities. EPA's air quality modeling relies on this comprehensive set of emissions inventories because emissions from multiple source categories are needed to model ambient air quality and to facilitate comparison of model outputs with ambient measurements.

subject of a pending challenge in federal court. *Pawnee Nation of Oklahoma* v. *Regan,* No. 20–9635 (10th Cir.).

[97] Ramboll Environment and Health, January 2021, *http://www.camx.com.*

To prepare the emissions inventories for air quality modeling, the EPA processed the emissions inventories using the Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System version 4.8.1 to produce the gridded, hourly, speciated, model-ready emissions for input to the air quality model. Additional information on the development of the emissions inventories and on data sets used during the emissions modeling process are provided in the TSD titled, ''Preparation of Emissions Inventories for the 2016v2 North American Emissions Modeling Platform,'' hereafter known as the ''Emissions Modeling TSD.'' This TSD is available in the docket for this rule.

1. Foundation Emissions Inventory Data Sets

The 2016v2 emissions platform is comprised of data from various sources including data developed using models, methods, and source datasets that became available in calendar years 2020 and 2021, in addition to data from the Inventory Collaborative 2016 version 1 (2016v1) Emissions Modeling Platform, released in October 2019. The 2016v1 platform was developed through a national collaborative effort between the EPA and state and local agencies along with MJOs and included emissions inventories for the years 2016, 2023, and 2028. For this proposed rule, emissions inventories were developed for the years 2016, 2023, 2026, and 2032 that represent changes in activity data and of predicted emissions reductions from on-the-books actions, planned emissions control installations, and promulgated federal measures that affect anthropogenic emissions.[98] The 2016 emissions inventories for the U.S. include data derived from the 2017 National Emissions Inventory (2017NEI) and some data derived from the 2014 National Emissions Inventory (NEI), version 2 (2014NEIv2). All of the inventory sectors were updated to better represent the year 2016 through the incorporation of 2016-specific state and local data along with nationally applied adjustment methods. The following sections provide an overview of the construct of the 2016v2 emissions and projections.

2. Development of Emissions Inventories for EGUs

Annual NO_X and SO_2 emissions for EGUs in the 2016 base year inventory are based primarily on data from continuous emissions monitoring systems (CEMS) and other monitoring systems allowed for use by qualifying units under 40 CFR part 75, with other EGU pollutants estimated using emissions factors and annual heat input data reported to the EPA. For EGUs not reporting under part 75, the EPA used data submitted to the NEI and the 2016v1 platform by the states. Emissions data for EGUs that did not have data provided for the year 2016 were pulled forward from data submitted for the 2014 NEI. The Air Emissions Reporting Rule, (80 FR 8787; February 19, 2015), requires that Type A point sources large enough to meet or exceed specific thresholds for emissions be reported to the EPA every year, while the smaller Type B point sources must only be reported to EPA every 3 years.

The EPA projected future 2023, 2026, and 2032 baseline EGU emissions using the version 6—Summer 2021 Reference Case of the Integrated Planning Model (IPM). IPM, developed by ICF Consulting, is a state-of-the-art, peer-reviewed, multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. The EPA has used IPM for over two decades, including all prior implemented CSAPR rulemakings, to better understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emissions impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. The EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs.[99]

The IPM version 6—Summer 2021 Reference Case incorporated recent updates through the Summer of 2021 to account for updated federal and state environmental regulations (including Renewable Portfolio Standards (RPS), Clean Energy Standards (CES) and other state mandates), fleet changes (committed EGU retirements and new builds), electricity demand, technology cost and performance assumptions from recent data (for renewables adopting from National Renewable Energy Lab (NREL's) Annual Technology Baseline 2020 and for fossil sources from U.S. Energy Information Agency's (EIA) Annual Energy Outlook (AEO) 2020. Natural gas and coal price projections reflect data developed in Fall 2020. The inventory of EGUs provided as an input to the model was the National Electric Energy Data System (NEEDS) Summer 2021 version and is available on EPA's website.[100] This version of NEEDS reflects announced retirements and under construction new builds known as of early summer 2021. This projected base case accounts for the effects of the finalized Mercury and Air Toxics Standards rule, CSAPR, the CSAPR Update, the Revised CSAPR Update, New Source Review settlements, the final Effluent Limitation Guidelines (ELG) Rule, the Coal Combustion Residual (CCR) Rule, and other on-the-books federal and state rules (including renewable energy tax credit extensions from the Consolidated Appropriations Act of 2021) through early 2021 impacting SO_2, NO_X, directly emitted particulate matter, CO_2, and power plant operations. It also includes final actions the EPA has taken to implement the Regional Haze Rule and BART requirements. IPM has projected output years for 2023 and 2025. IPM year 2025 outputs were adjusted for known retirements to be reflective of year 2026, and IPM year 2030 outputs were used for the year 2032 as is specified by the mapping of IPM output years to specific years.

Additional 2023 through 2026 EGU emissions baseline levels were developed through engineering analytics as an alternative approach that did not involve IPM. The EPA developed this inventory for use in Step 3 of this final rule, where it determines emissions reduction potential and corresponding state-level emissions budgets. IPM includes optimization and perfect foresight in solving for least cost dispatch. Given that this final rule will likely become effective immediately prior to the start of the 2023 ozone season, the EPA is adopting a similar approach to the CSAPR Update and the

[98] Biogenic emissions and emissions from wildfires and prescribed fires were held constant between 2016 and the future years because (1) these emissions are tied to the 2016 meteorological conditions and (2) the focus of this rule is on the contribution from anthropogenic emissions to projected ozone nonattainment and maintenance.

[99] Detailed information and documentation of EPA's Base Case, including all underlying assumptions, data sources, and architecture parameters can be found on EPA's website at: *https://www.epa.gov/airmarkets/epas-power-sector-modeling-platform-v6-using-ipm-summer-2021-reference-case.*

[100] *Available at https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6.*

Revised CSAPR Update where it relied on IPM in a relative way in Step 3 to avoid overstating optimization and dispatch decisions in state-emissions budget quantification that may not be possible in a short time frame. The EPA does this by using the difference in emissions rate observed between IPM runs with and without the cost threshold applied, rather than using absolute values. In both the CSAPR Update and in this rule at Step 3, EPA complemented that projected IPM EGU outlook with historical (*e.g.,* engineering analytics) perspective based on historical data that only factors in known changes to the fleet. This 2023 engineering analytics data set is described in more detail in the Ozone Transport Policy Analysis Proposed Rule TSD and corresponding Appendix A: State Emissions Budgets Calculations and Underlying Data. The Engineering Analysis used in Step 3 is also discussed further in Section VII.B of this proposed rule.

Both IPM and the Engineering Analytics tools are valuable for estimating future EGU emissions and examining the cone of uncertainty around any future sector-level inventory estimate. A key difference between the two tools is that IPM reflects both announced and projected changes in fleet operation, whereas the Engineering Analytics tool only reflects announced changes. By not including projected changes that are anticipated in response to market forces and fleet trends, the Engineering Analysis is deliberately conservative in its estimate of change in the power sector. Throughout all of the CSAPR rules to date, and prior interstate transport actions, the EPA has used IPM at Steps 1 and 2 as it is best suited for projecting emissions in an airshed, at projecting emissions for time horizons more than a few years out (for which changes would not yet be announced and thus projecting changes is critical), and for scenarios where the assumed change in emissions is not being codified into a state emissions reduction requirement. Using IPM at Steps 1 and 2 helps the EPA avoid overstating future year receptor values (Step 1) and future year linkages (Step 2) by reflecting reductions anticipated to occur within the airshed in the relevant timeframe.

Engineering analytics has been a useful tool for Step 3 state-level emissions reduction estimates in CSAPR rulemaking, because at that step EPA is dealing with more geographic granularity (state-level as opposed to regional air shed), more near-term (as opposed to medium-term) assessments, and scenarios where reduction estimates are codified into regulatory requirements. Using the Engineering Analytics tool at this step ensures that the EPA is not codifying into the base case, and consequently into state emissions budgets, changes in the power sector that are merely modeled to occur rather than announced by real-world actors.

Finally, both in the Revised CSAPR Update and in this rule, the EPA was able to use the Air Quality Assessment Tool to verify that regardless of which EGU inventory is used, the 2023 starting geography of the program is not impacted. In other words, regardless of whether a stakeholder takes a more comprehensive view of the EGU future (IPM) or a more conservative view of change in the EGU fleet (Engineering Analysis) the starting geography would be the same. This finding is consistent with the observation that EGUs are now less than 10% of the total ozone-season NO_X inventory and the degree of near-term difference between the IPM and Engineering Analytic regional projections is relatively small on the regional level. While the EPA continues to believe that IPM is best suited for Step 1 and Step 2, and engineering analytics is best suited for Step 3 efforts in this rulemaking, the Agency is requesting comment on the EGU emissions inventory most reasonable for Step 1 and Step 2 in the analysis. The Ozone Transport Policy Analysis Proposed Rule TSD contains data on 2023 and 2026 AQ impacts of each dataset.

3. Development of Emissions Inventories for Non-EGU Point Sources

The updates to the non-EGU point source emissions include a few sources being moved to the EGU inventory and additional control efficiency information for the year 2016. In the 2016v2 platform, some non-EGU point source emissions were based on data submitted for 2016, others were projected from 2014 to 2016, and the emissions for any remaining small sources were kept at 2014 levels. Prior to air quality modeling, the emissions inventories were processed into a format that is appropriate for the air quality model to use. The future year non-EGU point inventories were grown from 2016 to the future years using factors based on the AEO 2021 except for limited cases where errors were identified with the AEO 2021 data in which case data from AEO 2020 were used. The future year inventories reflect emissions reductions due to national and local rules, control programs, plant closures, consent decrees, and settlements. Reductions from several Maximum Achievable Control Technology and National Emissions Standards for Hazardous Air Pollutants (NESHAP) standards are included. Projection approaches for corn ethanol and biodiesel plants, refineries and upstream impacts represent requirements pursuant to the Energy Independence and Security Act of 2007 (EISA).

Aircraft emissions and ground support equipment at airports are represented as point sources and are based on adjustments to emissions in the January 2021 version of the 2017 NEI (see *https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data* for data and a TSD). A notable update in the January 2021 version of the 2017 NEI as compared to the April 2020 version was a correction to some double counting of some airport emissions. This correction is incorporated into the inventories for this proposed rule. The EPA developed and applied factors to adjust the 2017 airport emissions to 2016, 2023, 2026, and 2032 based on activity growth projected by the Federal Aviation Administration 2019 Terminal Area Forecast [101] system, the latest available version at the time the factors were developed.

Emissions at rail yards were represented as point sources. The 2016 rail yard emissions are largely consistent with the 2017 NEI rail yard emissions. The 2016 and 2023 rail yard emissions were developed through the 2016v1 Inventory Collaborative process, with the 2026 emissions interpolated between the 2023 and 2028 emissions from 2016v1 rail yard emissions were interpolated from the 2016 and 2023 emissions. Class I rail yard emissions were projected based on the AEO freight rail energy use growth rate projections for 2016, 2023, and 2032 with the fleet mix assumed to be constant throughout the period.

Point source oil and gas emissions for 2016 were based on the 2016v1 point inventory except that an inventory generated by the Western Regional Air Partnership (WRAP) [102] was used for the states of Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming. The 2016 oil and gas inventories were first projected to 2019 values based on actual production data, and those 2019 emissions were projected to 2023, 2026, and 2032 using regional projection factors by product type based on AEO 2021 projections. NO_X and VOC reductions that are co-

[101] *https://www.faa.gov/data_research/aviation/taf/.*

[102] *http://www.wrapair2.org/pdf/WRAP_OGWG_Report_Baseline_17Sep2019.pdf.*

benefits to the NESHAP and New Source Performance Standards (NSPS) for Stationary Reciprocating Internal Combustion Engines (RICE) are reflected for select source categories. In addition, Natural Gas Turbines and Process Heaters NSPS NO_X controls and NSPS Oil and Gas VOC controls [103] are reflected for select source categories. The WRAP future year inventory was used in WRAP states in all future years.[104]

4. Development of Emissions Inventories for Onroad Mobile Sources

Onroad mobile sources include exhaust, evaporative, and brake and tire wear emissions from vehicles that drive on roads, parked vehicles, and vehicle refueling. Emissions from vehicles using regular gasoline, high ethanol gasoline, diesel fuel, and electric vehicles were represented, along with buses that used compressed natural gas. The EPA developed the onroad mobile source emissions for states other than California using EPA's Motor Vehicle Emissions Simulator (MOVES). MOVES3 was released in November 2020 and has been followed by some minor releases that improved the usage of the model but that do not have substantive impacts on the emissions estimates. For this proposal, MOVES3 was run using inputs provided by state and local agencies through the 2017 NEI where available, in combination with nationally available data sets to develop a complete inventory. Onroad emissions for 2016v2 were developed based on emissions factors output from MOVES3 run for the year 2016, coupled with activity data (*e.g.,* vehicle miles traveled and vehicle populations) representing the year 2016. The 2016 activity data were provided by some state and local agencies through the 2016v1 process, and the remaining activity data were derived from the 2017 NEI. The onroad emissions were computed within SMOKE by multiplying emissions factors developed using MOVES with the appropriate activity data. Onroad mobile source emissions for California were consistent with the emissions data provided by the state.

The future-year emissions estimates for onroad mobile sources represent all national control programs known at the time of modeling including rules newly added in MOVES3: The Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles (HDGHG)—Phase 2 [105] and the Safer Affordable Fuel-Efficient (SAFE) Vehicles Rule.[106] Other finalized rules incorporated into the onroad mobile source emissions estimates include: Tier 3 Standards (March 2014), the Light-Duty Greenhouse Gas Rule (March 2013), Heavy (and Medium)-Duty Greenhouse Gas Rule (August 2011), the Renewable Fuel Standard (February 2010), the Light Duty Greenhouse Gas Rule (April 2010), the Corporate-Average Fuel Economy standards for 2008–2011 (April 2010), the 2007 Onroad Heavy-Duty Rule (February 2009), and the Final Mobile Source Air Toxics Rule (MSAT2) (February 2007). Estimates of the impacts of rules that were in effect in 2016 are included in the 2016 base year emissions at a level that corresponds to the extent to which each rule had penetrated into the fleet and fuel supply by the year 2016. Local control programs such as the California LEV III program for criteria pollutants are included in the onroad mobile source emissions.

The future year onroad emissions reflect projected changes to fuel properties and usage, along with the impact of the rules included in MOVES3 for each of the future years. MOVES was run for the years 2023, 2026, and 2032 to generate the emissions factors relevant to those years. Future year activity data for onroad mobile sources were provided by some state and local agencies, and otherwise were projected to 2023, 2026, and 2032 by first projecting the 2016 activity to year 2019 based on county level vehicle miles traveled (VMT) from the Federal Highway Administration, and then from 2019 to the future years using AEO 2021-based factors. The future year emissions were computed within SMOKE by multiplying the future year emissions factors developed using MOVES with the year-specific activity data.

5. Development of Emissions Inventories for Commercial Marine Vessels

The commercial marine vessel (CMV) emissions in the 2016 base case emissions inventory for this rule were based on those in the 2017 NEI. Factors were then applied to adjust the 2017 NEI emissions backward to represent emissions for the year 2016. The CMV emissions reflect reductions associated with the Emissions Control Area proposal to the International Maritime Organization control strategy (EPA–420–F–10–041, August 2010); reductions of NO_X, VOC, and CO emissions for new C3 engines that went into effect in 2011; and fuel sulfur limits that went into effect prior to 2016. The cumulative impacts of these rules through 2023, 2026 and 2030 [107] were incorporated into the projected emissions for CMV sources. The CMV emissions were split into emissions inventories from the larger category 3 (C3) engines, and those from the smaller category 1 and 2 (C1C2) engines. CMV emissions in California are based on emissions provided by the state. The CMV emissions are consistent with the emissions for the 2016v1 platform updated CMV emissions released by February 2020 although they include future years of 2026 and 2030 instead of 2028.

6. Development of Emissions Inventories for Other Nonroad Mobile Sources

Nonroad mobile source emissions inventories (other than CMV, locomotive, and aircraft emissions) were developed from monthly, county, and process level emissions output from MOVES3. Types of nonroad equipment include recreational vehicles, pleasure craft, and construction, agricultural, mining, and lawn and garden equipment. State-submitted emissions data for nonroad sources were used for California.

The EPA also ran MOVES3 for 2023, 2026, and 2032 to prepare nonroad mobile emissions inventories for future years. The nonroad mobile emissions control programs include reductions to locomotives, diesel engines, and recreational marine engines, along with standards for fuel sulfur content and evaporative emissions. A comprehensive list of control programs included for mobile sources is available in the Emissions Modeling TSD.

[103] On November 15, 2021, the EPA published proposed revisions to standards of performance for new, reconstructed, and modified sources and proposed revisions to emissions guidelines for existing sources in the oil and natural gas sector at 86 FR 63110. Emissions reductions from proposed federal regulatory programs are not included in EPA's baseline analyses until they have been finalized.

[104] *http://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_RevFinalReport_05March2020.pdf.*

[105] The effect of the HDGHG Phase 2 rule on criteria pollutants is estimated in Table 5–48 of the Regulatory Impact Analysis, available from *https://nepis.epa.gov/Exe/ZyPDF.cgi/P100P7NS.PDF?Dockey=P100P7NS.PDF.*

[106] Information on the SAFE vehicles rule is available from *https://www.epa.gov/regulations-emissions-vehicles-and-engines/safer-affordable-fuel-efficient-safe-vehicles-final-rule.* Preliminary analysis by the Office of Transportation and Air Quality of the impact of this rule on criteria pollutants show impacts of less than 1 percent for VOC and no impact for NO_X.

[107] CMV emissions were projected out to 2030 instead of 2032 because that was the last year of data available in a dataset used in the projections process. The year 2030 inventories were used in the 2032 emissions case.

Line haul locomotives are also considered a type of nonroad mobile source but the emissions inventories for locomotives were not developed using MOVES3. Year 2016 and 2023 locomotive emissions were developed through the 2016v1 process and the year 2016 emissions are mostly consistent with those in the 2017 NEI. The projected locomotive emissions for 2023, 2026, and 2030[108] were developed by applying factors to the base year emissions using activity data based on AEO freight rail energy use growth rate projections along with emissions rates adjusted to account for recent historical trends.

7. Development of Emissions Inventories for Nonpoint Sources

Some emissions for stationary nonpoint sources in the 2016 base case emissions inventory come from the 2017 NEI adjusted to 2016 levels, while others are based on data from the 2014NEIv2 adjusted to reflect year 2016 more closely using factors based on changes to human population from 2014 to 2016. Stationary nonpoint sources include evaporative sources, consumer products, fuel combustion that is not captured by point sources, agricultural livestock, agricultural fertilizer, residential wood combustion, fugitive dust, and oil and gas sources. The emissions sources based on the 2017 NEI include agricultural livestock, fugitive dust, residential wood combustion, waste disposal (including composting), bulk gasoline terminals, and miscellaneous non-industrial sources such as cremation, hospitals, lamp breakage, and automotive repair shops. A new method for solvent VOC emissions was used.[109]

Where states provided the Inventory Collaborative information about projected control measures or changes in nonpoint source emissions for 2016v1 or 2016v2, those inputs were incorporated into the projected inventories for 2023, 2026, and 2032 to the extent possible. Where possible, projection factors based on the AEO were based on AEO 2021. Adjustments for state fuel sulfur content rules for fuel oil in the Northeast were included. Projected emissions for portable fuel containers reflect the impact of projection factors required by the final MSAT2 rule and the EISA, including updates to cellulosic ethanol plants, ethanol transport working losses, and ethanol distribution vapor losses.

For 2016, nonpoint oil and gas emissions inventories were developed based on a run of the 2017 NEI version of the EPA Oil and Gas Tool with data for year 2016 coupled with the WRAP inventory for production-related nonpoint oil and gas emissions in the states of Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming, and a California Air Resources Board-provided inventory was used for emissions in California. Nonpoint oil and gas emissions in other states and exploration-related emissions in the WRAP states were based on a run of the 2017 NEI version of the EPA Oil and Gas Tool with input data for the year 2016. The 2016 oil and gas inventories were first projected to 2019 values based on actual production data, and those 2019 emissions were projected to 2023, 2026, and 2032 using regional projection factors by product type based on AEO 2021 projections. NO_X and VOC reductions that are co-benefits to the NESHAP and NSPS for RICE are reflected for select source categories. In addition, Natural Gas Turbines and Process Heaters NSPS NO_X controls and NSPS Oil and Gas VOC controls are reflected for select source categories. The WRAP future year inventory was used in WRAP states in all future years.[110]

D. Air Quality Modeling To Identify Nonattainment and Maintenance Receptors

In this section, the Agency describes the air quality modeling and analyses performed in Step 1 to identify locations where the Agency expects there to be nonattainment or maintenance receptors for the 2015 ozone NAAQS in the 2023, 2026, and 2032 analytic future years. Where EPA's analysis shows that an area or site does not fall under the definition of a nonattainment or maintenance receptor in 2023, that site is excluded from further analysis under EPA's good neighbor framework.

In this proposed rule, the EPA is applying the same approach used in the CSAPR Update and the Revised CSAPR Update to identify nonattainment and maintenance receptors for the 2008 ozone NAAQS. *See* 86 FR 23078–79.

EPA's approach gives independent effect to both the ''contribute significantly to nonattainment'' and the ''interfere with maintenance'' prongs of section 110(a)(2)(D)(i)(I), consistent with the D.C. Circuit's direction in *North Carolina.*[111] Further, in its decision on the remand of the CSAPR from the Supreme Court in the *EME Homer City* case, the D.C. Circuit confirmed that EPA's approach to identifying maintenance receptors in the CSAPR comported with the court's prior instruction to give independent meaning to the ''interfere with maintenance'' prong in the good neighbor provision. *EME Homer City II,* 795 F.3d at 136.

In the CSAPR Update and the Revised CSAPR Update, the EPA identified nonattainment receptors as those monitoring sites that are projected to have average design values that exceed the NAAQS and that are also measuring nonattainment based on the most recent monitored design values. This approach is consistent with prior transport rulemakings, such as the NO_X SIP Call and CAIR, where the EPA defined nonattainment receptors as those areas that both currently monitor nonattainment and that the EPA projects will be in nonattainment in the future compliance year.[112]

The Agency explained in the NO_X SIP Call and CAIR and then reaffirmed in the CSAPR Update that the EPA has the most confidence in our projections of nonattainment for those counties that also measure nonattainment for the most recent period of available ambient data. The EPA separately identified maintenance receptors as those receptors that would have difficulty maintaining the relevant NAAQS in a scenario that accounts for historical variability in air quality at that receptor. The variability in air quality was determined by evaluating the ''maximum'' future design value at each receptor based on a projection of the maximum measured design value over the relevant period. The EPA interprets the projected maximum future design value to be a potential future air quality outcome consistent with the meteorology that yielded maximum measured concentrations in the ambient data set analyzed for that receptor (*i.e.,* ozone conducive meteorology). The EPA also recognizes that previously experienced meteorological conditions (*e.g.,* dominant wind direction, temperatures, and air mass patterns) promoting ozone formation that led to maximum concentrations in the measured data may reoccur in the

[108] The farthest out year for which locomotive emissions were projected was 2030 and those were used in the 2032 case.

[109] *https://doi.org/10.5194/acp-21-5079-2021.*

[110] *http://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_RevFinalReport_05March2020.pdf.*

[111] 531 F.3d at 910–911 (holding that the EPA must give ''independent significance'' to each prong of CAA section 110(a)(2)(D)(i)(I)).

[112] *See* 63 FR 57375, 57377 (October 27, 1998); 70 FR 25241(January 14, 2005). *See also North Carolina,* 531 F.3d at 913–914 (affirming as reasonable EPA's approach to defining nonattainment in CAIR).

future. The maximum design value gives a reasonable projection of future air quality at the receptor under a scenario in which such conditions do, in fact, reoccur.[113] The projected maximum design value is used to identify upwind emissions that, under those circumstances, could interfere with the downwind area's ability to maintain the NAAQS.

Therefore, applying this methodology in this proposed rule, EPA assessed the magnitude of the maximum projected design values for 2023, 2026, and 2032 at each receptor in relation to the 2015 ozone NAAQS and, where such a value exceeds the NAAQS, the EPA determined that receptor to be a ''maintenance'' receptor for purposes of defining interference with maintenance, consistent with the method used in CSAPR and upheld by the D.C. Circuit in *EME Homer City II*.[114] That is, monitoring sites with a maximum design value that exceeds the NAAQS are projected to have maintenance problems in the future analytic years.[115]

Recognizing that nonattainment receptors are also, by definition, maintenance receptors, the EPA often uses the term ''maintenance-only'' to refer to receptors that are not also nonattainment receptors. Consistent with the concepts for maintenance receptors, as described above, the EPA identifies ''maintenance-only'' receptors as those monitoring sites that have projected average design values above the level of the applicable NAAQS, but that are not currently measuring nonattainment based on the most recent official design values. In addition, those monitoring sites with projected average design values below the NAAQS, but with projected maximum design values above the NAAQS are also identified as ''maintenance only'' receptors, even if they are currently measuring nonattainment based on the most recent official design values.

Consistent with EPA's modeling guidance, the 2016 base year and future year air quality modeling results were used in a relative sense to project design values for 2023, 2026, and 2032. That is, the ratios of future year model predictions to base year model predictions are used to adjust ambient ozone design values[116] up or down depending on the relative (percent) change in model predictions for each location. The modeling guidance recommends using measured ozone concentrations for the 5-year period centered on the base year as the air quality data starting point for future year projections. This average design value is used to dampen the effects of inter-annual variability in meteorology on ozone concentrations and to provide a reasonable projection of future air quality at the receptor under average conditions. In addition, the Agency calculated maximum design values from within the 5-year base period to represent conditions when meteorology is more favorable than average for ozone formation. Because the base year for the air quality modeling used in this proposed rule is 2016, measured data for 2014–2018 (*i.e.,* design values for 2016, 2017, and 2018) were used in order to project average and maximum design values in 2023, 2026, and 2032.

The ozone predictions from the 2016 and future year air quality model simulations were used to project 2016–2018 average and maximum ozone design values to 2023, 2026, and 2032 using an approach similar to the approach in EPA's guidance for attainment demonstration modeling. This guidance recommends using model predictions from the 3 x 3 array of grid cells[117] surrounding the location of the monitoring site to calculate a Relative Response Factor (RRF) for that site.[118] The 2016–2018 base period average and maximum design values were multiplied by the RRF to project each of these design values to each of the three future years. In this manner, the projected design values are grounded in monitored data, and not the absolute model-predicted future year concentrations. Following the approach in the CSAPR Update and the Revised CSAPR Update, the EPA also projected future year design values based on a modified version of the ''3 x 3'' approach for those monitoring sites located in coastal areas. In this alternative approach, EPA eliminated from the RRF calculations the modeling data in those grid cells that are dominated by water (*i.e.,* more than 50 percent of the area in the grid cell is water) and that do not contain a monitoring site (*i.e.,* if a grid cell is more than 50 percent water but contains an air quality monitor, that cell would remain in the calculation). The choice of more than 50 percent of the grid cell area as water as the criteria for identifying overwater grid cells is based on the treatment of land use in the Weather Research and Forecasting model (WRF).[119] Specifically, in the WRF meteorological model those grid cells that are greater than 50% overwater are treated as being 100 percent overwater. In such cases the meteorological conditions in the entire grid cell reflect the vertical mixing and winds over water, even if part of the grid cell also happens to be over land with land-based emissions, as can often be the case for coastal areas. Overlaying land-based emissions with overwater meteorology may be representative of conditions at coastal monitors during times of on-shore flow associated with synoptic conditions or sea-breeze or lake-breeze wind flows. But there may be other times, particularly with off-shore wind flow, when vertical mixing of land-based emissions may be too

[113] The EPA's air quality modeling guidance identifies the use of the highest of the relevant base period design values as a means to evaluate future year attainment under meteorological conditions that are especially conducive to ozone formation. *See* U.S. Environmental Protection Agency, 2018. Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze, Research Triangle Park, NC.

[114] *See* 795 F.3d at 136.

[115] The EPA issued a memorandum in October 2018, providing additional information to states developing interstate transport SIP submissions for the 2015 8-hour ozone NAAQS concerning considerations for identifying downwind areas that may have problems maintaining the standard at Step 1 of the 4-step interstate transport framework. *See* Considerations for Identifying Maintenance Receptors for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, October 19, 2018 (''October 2018 memorandum''), available in Docket No. EPA–HQ–OAR–2021–0663 or at *https://www.epa.gov/airmarkets/memo-and-supplemental-information-regarding-interstate-transport-sips-2015-ozone-naaqs.* The EPA does not propose to adopt the information or suggested analytical approaches in that memorandum in this proposed rule proposing FIPs. Potential alternative approaches would introduce unnecessary and substantial additional analytical burdens that could frustrate timely and efficient implementation of good neighbor obligations. In addition, the information supplied in that memorandum is now outdated due to several additional years of air quality monitoring data and updated modeling results. EPA's current approach to defining ''maintenance'' receptors has been upheld and continues to provide an appropriate approach to addressing the ''interference with maintenance'' prong of the Good Neighbor provision. *See EME Homer City,* 795 F.3d 118, 136–37; *Wisconsin,* 938 F.3d at 325–26.

[116] The ozone design value at a particular monitoring site is the 3-year average of the annual 4th highest daily maximum 8-hour ozone concentration at that site.

[117] As noted above, each model grid cell is 12 x 12 km.

[118] The relative response factor represents the change in ozone at a given site. In order to calculate the RRF, EPA's modeling guidance recommends selecting the 10 highest ozone days in an ozone season at a given monitor in the base year, noting which of the grid cells surrounding the monitor experienced the highest ozone concentrations in the base year, and averaging those ten highest concentrations. The model is then run using the projected year emissions, in this case 2023, with all other model variables held constant. Ozone concentrations from the same ten days, in the same grid cells, are then averaged. The fractional change between the base year (2016 model run) averaged ozone concentrations and the future year (*e.g.,* 2023 model run) averaged ozone concentrations represents the relative response factor.

[119] *https://www.mmm.ucar.edu/weather-research-and-forecasting-model.*

limited due to the presence of overwater meteorology. Thus, for our modeling EPA projected average and maximum design values at individual monitoring sites based on both the ''3 x 3'' approach as well as the alternative approach that eliminates overwater cells in the RRF calculation for near-coastal areas (*i.e.,* ''no water'' approach). The projected 2023, 2026, and 2032 design values using both the ''3 x 3'' and ''no-water'' approaches are provided in the docket for this proposed rule. For this proposed rule, the EPA is relying upon design values based on the ''no water'' approach for identifying nonattainment and maintenance receptors.[120]

Consistent with the truncation and rounding procedures for the 8-hour ozone NAAQS, the projected design values are truncated to integers in units of ppb.[121] Therefore, projected design values that are greater than or equal to 71 ppb are considered to be violating the 2015 ozone NAAQS. For those sites that are projected to be violating the NAAQS based on the average design values in the future analytic years, the Agency examined the measured design values for 2020, which are the most recent official measured design values at the time of this proposal. As noted earlier, the Agency proposes to identify nonattainment receptors in this rulemaking as those sites that are violating the NAAQS based on current measured air quality and also have projected average design values of 71 ppb or greater. Maintenance-only receptors include both (1) those sites with projected average design values above the NAAQS that are currently measuring clean data and (2) those sites with projected average design values below the level of the NAAQS, but with projected maximum design values of 71 ppb or greater. In addition to the maintenance-only receptors, the 2021 ozone nonattainment receptors are also maintenance receptors because the maximum design values for each of these sites is always greater than or equal to the average design value. The monitoring sites that the Agency projects to be nonattainment and maintenance receptors for the ozone NAAQS in the 2023 and 2026 base case are used for assessing the contribution of emissions in upwind states to downwind nonattainment and maintenance of ozone NAAQS as part of this proposal.

Table V.D–1 contains the 2016-centered[122] base period average and maximum 8-hour ozone design values, the 2023 base case average and maximum design values and the 2020 design values for the sites that are projected to be nonattainment receptors in 2023. Table V.D–2 contains this same information for monitoring sites that are projected to be maintenance-only receptors in 2023. The design values for all monitoring sites in the U.S. are provided in the docket for this rule. Additional details on the approach for projecting average and maximum design values are provided in the AQM TSD.

TABLE V.D–1—AVERAGE AND MAXIMUM 2016-CENTERED AND 2023 BASE CASE 8-HOUR OZONE DESIGN VALUES AND 2020 DESIGN VALUES (ppb) AT PROJECTED NONATTAINMENT RECEPTORS *

Monitor ID	State	County	2016 centered average	2016 centered maximum	2023 average	2023 maximum	2020
060170010	CA	El Dorado	85.3	88	76.3	78.7	84
060170020	CA	El Dorado	82.0	84	74.3	76.2	80
060190007	CA	Fresno	87.0	89	80.4	82.2	80
060190011	CA	Fresno	90.0	91	82.9	83.8	84
060190242	CA	Fresno	84.3	86	79.5	81.1	79
060194001	CA	Fresno	90.3	92	82.8	84.4	81
060195001	CA	Fresno	91.0	94	83.7	86.4	84
060250005	CA	Imperial	76.7	77	76.3	76.6	78
060251003	CA	Imperial	76.0	76	75.4	75.4	68
060290007	CA	Kern	87.7	89	82.8	84.0	93
060290008	CA	Kern	83.0	85	79.1	81.0	85
060290011	CA	Kern	83.3	85	78.8	80.4	86
060290014	CA	Kern	86.0	88	81.3	83.2	85
060290232	CA	Kern	79.3	82	74.9	77.5	83
060292012	CA	Kern	89.3	90	84.1	84.7	85
060295002	CA	Kern	87.3	89	82.4	84.0	89
060296001	CA	Kern	80.7	81	77.1	77.4	82
060311004	CA	Kings	83.3	84	76.9	77.6	80
060370002	CA	Los Angeles	94.3	99	88.0	92.4	97
060370016	CA	Los Angeles	100.0	103	93.4	96.2	107
060371201	CA	Los Angeles	88.3	91	82.7	85.3	92
060371602	CA	Los Angeles	75.7	76	73.6	73.9	78
060371701	CA	Los Angeles	92.0	95	85.6	88.4	88
060372005	CA	Los Angeles	84.7	86	80.7	81.9	93
060376012	CA	Los Angeles	98.0	100	91.6	93.4	101
060379033	CA	Los Angeles	87.3	89	80.7	82.2	80
060390004	CA	Madera	80.3	83	75.7	78.3	76
060392010	CA	Madera	82.7	84	77.0	78.2	78
060430003	CA	Mariposa	76.0	79	74.2	77.1	79
060470003	CA	Merced	80.7	82	74.7	75.9	76
060570005	CA	Nevada	86.3	90	78.1	81.5	82

[120] Using design values from the ''3 x 3'' approach, the maintenance-only receptor at site 170317002 in Cook County, IL would become a nonattainment receptor because the average design value with the ''3 x 3'' approach is 71.1 ppb versus 70.1 ppb with the ''no water'' approach. In addition, the monitor at site 170971007 in Lake County, IL which was not projected to be a receptor using the ''no water'' approach would be a maintenance-only receptor with the ''3 x 3'' approach because the maximum design value with the ''no water'' approach was 69.9 ppb versus a maximum design value of 71.2 ppb with the ''3 x 3'' approach. However, including this Lake County, Illinois site as a receptor would not affect which states are covered by this proposed rule.

[121] 40 CFR part 50, Appendix P to Part 50—Interpretation of the Primary and Secondary National Ambient Air Quality Standards for Ozone.

[122] 2016-centered averaged design values represent the average of the design values for 2016, 2017, and 2018. Similarly, the maximum 2016-centered design value is the highest measured design value from these three design value periods.

TABLE V.D–1—AVERAGE AND MAXIMUM 2016-CENTERED AND 2023 BASE CASE 8-HOUR OZONE DESIGN VALUES AND 2020 DESIGN VALUES (ppb) AT PROJECTED NONATTAINMENT RECEPTORS *—Continued

Monitor ID	State	County	2016 centered average	2016 centered maximum	2023 average	2023 maximum	2020
060592022	CA	Orange	77.7	78	72.5	72.8	82
060595001	CA	Orange	75.3	76	72.3	73.0	77
060610003	CA	Placer	85.0	88	77.1	79.8	N/A
060610004	CA	Placer	79.3	85	71.9	77.0	N/A
060610006	CA	Placer	80.0	81	72.8	73.7	72
060650008	CA	Riverside	76.5	79	71.0	73.3	N/A
060650012	CA	Riverside	95.3	98	85.9	88.3	99
060650016	CA	Riverside	79.0	80	72.0	72.9	78
060651016	CA	Riverside	99.7	101	89.8	90.9	99
060652002	CA	Riverside	82.7	85	76.4	78.5	84
060655001	CA	Riverside	88.7	91	80.5	82.6	88
060656001	CA	Riverside	92.3	93	83.5	84.1	94
060658001	CA	Riverside	96.7	98	89.5	90.7	96
060658005	CA	Riverside	95.0	98	87.9	90.7	98
060659001	CA	Riverside	88.7	91	80.8	82.9	87
060670002	CA	Sacramento	77.7	78	71.4	71.7	72
060670012	CA	Sacramento	82.3	83	74.8	75.4	N/A
060710001	CA	San Bernardino	79.0	80	74.5	75.4	81
060710005	CA	San Bernardino	110.3	112	100.3	101.8	109
060710012	CA	San Bernardino	95.0	98	87.3	90.1	90
060710306	CA	San Bernardino	84.0	86	76.8	78.6	83
060711004	CA	San Bernardino	105.7	109	97.2	100.2	106
060712002	CA	San Bernardino	97.7	99	90.1	91.3	102
060714001	CA	San Bernardino	90.3	91	82.6	83.3	87
060714003	CA	San Bernardino	104.0	107	95.2	98.0	114
060719002	CA	San Bernardino	87.3	89	80.1	81.6	86
060719004	CA	San Bernardino	108.7	111	99.5	101.6	110
060731006	CA	San Diego	83.0	84	76.9	77.9	79
060773005	CA	San Joaquin	77.3	79	71.3	72.8	70
060990005	CA	Stanislaus	81.0	82	75.4	76.3	79
060990006	CA	Stanislaus	83.7	84	77.5	77.8	80
061030004	CA	Tehama	79.7	81	72.3	73.4	74
061070006	CA	Tulare	84.7	86	79.1	80.3	83
061070009	CA	Tulare	89.0	89	82.6	82.6	88
061072002	CA	Tulare	82.7	85	75.5	77.6	83
061072010	CA	Tulare	84.0	86	77.0	78.8	80
061090005	CA	Tuolumne	80.7	83	75.6	77.8	77
080350004	CO	Douglas	77.3	78	71.7	72.3	81
080590006	CO	Jefferson	77.3	78	72.6	73.3	79
080590011	CO	Jefferson	79.3	80	73.8	74.4	80
080690011	CO	Larimer	75.7	77	71.3	72.6	75
090010017	CT	Fairfield	79.3	80	73.0	73.7	82
090013007	CT	Fairfield	82.0	83	74.2	75.1	80
090019003	CT	Fairfield	82.7	83	76.1	76.4	79
090099002	CT	New Haven	79.7	82	71.8	73.9	80
481671034	TX	Galveston	75.7	77	71.1	72.3	74
482010024	TX	Harris	79.3	81	75.2	76.8	79
482010055	TX	Harris	76.0	77	71.0	72.0	76
490110004	UT	Davis	75.7	78	72.9	75.1	77
490353006	UT	Salt Lake	76.3	78	73.6	75.3	74
490353013	UT	Salt Lake	76.5	77	74.4	74.9	73
550590019	WI	Kenosha	78.0	79	72.8	73.7	74
551010020	WI	Racine	76.0	78	71.3	73.2	73
551170006	WI	Sheboygan	80.0	81	73.6	74.5	75

* "N/A" is used to denote that there is no valid 2020 design value.

TABLE V.D–2—AVERAGE AND MAXIMUM 2016-CENTERED AND 2023 BASE CASE 8-HOUR OZONE DESIGN VALUES AND 2020 DESIGN VALUES (ppb) AT PROJECTED MAINTENANCE-ONLY RECEPTORS

Monitor ID	State	County	2016 centered average	2016 centered maximum	2023 average	2023 maximum	2020
040278011	AZ	Yuma	72.3	74	70.5	72.2	68
060070007	CA	Butte	76.7	79	68.9	71.0	73
060090001	CA	Calaveras	77.0	78	70.9	71.9	72
060371103	CA	Los Angeles	73.0	74	70.5	71.5	76
060430006	CA	Mariposa	75.0	76	70.1	71.0	79

TABLE V.D–2—AVERAGE AND MAXIMUM 2016-CENTERED AND 2023 BASE CASE 8-HOUR OZONE DESIGN VALUES AND 2020 DESIGN VALUES (ppb) AT PROJECTED MAINTENANCE-ONLY RECEPTORS—Continued

Monitor ID	State	County	2016 centered average	2016 centered maximum	2023 average	2023 maximum	2020
060675003	CA	Sacramento	77.3	79	70.2	71.7	70
060711234	CA	San Bernardino	72.3	76	70.6	74.2	76
061112002	CA	Ventura	77.3	78	70.9	71.6	77
170310001	IL	Cook	73.0	77	69.6	73.4	75
170310032	IL	Cook	72.3	75	69.8	72.4	74
170310076	IL	Cook	72.0	75	69.3	72.1	69
170314201	IL	Cook	73.3	77	69.9	73.4	77
170317002	IL	Cook	74.0	77	70.1	73.0	75
320030075	NV	Clark	75.0	76	70.0	71.0	74
350130021	NM	Dona Ana	72.7	74	70.9	72.2	78
350130022	NM	Dona Ana	71.3	74	69.5	72.1	74
420170012	PA	Bucks	79.3	81	70.7	72.2	74
480391004	TX	Brazoria	74.7	77	70.1	72.3	73
481210034	TX	Denton	78.0	80	70.4	72.2	72
481410037	TX	El Paso	71.3	73	69.6	71.3	76
482011034	TX	Harris	73.7	75	70.3	71.6	73
482011035	TX	Harris	71.3	75	68.0	71.6	70
490450004	UT	Tooele	73.5	74	70.8	71.3	69
490570002	UT	Weber	73.0	75	70.6	72.5	N/A
490571003	UT	Weber	73.0	74	70.5	71.5	71
550590025	WI	Kenosha	73.7	77	69.2	72.3	74

In total, in the 2023 base case there are a total of 111 receptors nationwide including 85 nonattainment receptors and 26 maintenance-only receptors.[123] Of the 85 nonattainment receptors in 2023, 75 remain nonattainment receptors while 8 are projected to become maintenance-only receptors and 2 are projected to be in attainment in 2026. Of the 26 maintenance-only receptors in 2023, 13 are projected to remain maintenance-only receptors and 13 are projected to be in attainment in 2026. The projected average and maximum design values in 2026 for all receptors are included in the AQM TSD.

[123] The EPA's modeling also projects that three monitoring sites in the Uintah Basin (*i.e.,* monitor 490472003 in Uintah County, Utah and monitors 490130002 and 490137011 in Duchesne County, Utah) will have average design values above the NAAQS in 2023. However, as described in the AQM TSD, the Uinta Basin nonattainment area was designated as nonattainment for the 2015 ozone NAAQS not because of an ongoing problem with summertime ozone (as is usually the case in other parts of the country), but instead because it violates the ozone NAAQS in winter. The main causes of the Uinta Basin's wintertime ozone are sources located at low elevations within the Basin, the Basin's unique topography, and the influence of the wintertime meteorologic inversions that keep ozone and ozone precursors near the Basin floor and restrict air flow in the Basin. Because of the localized nature of the ozone problem at these sites the EPA has not identified these three monitors as receptors in Step 1 of this proposed rule.

E. Pollutant Transport From Upwind States

1. Air Quality Modeling To Quantify Upwind State Contributions

This section documents the procedures the EPA used to quantify the impact of emissions from specific upwind states on ozone design values in 2023 and 2026 for the identified downwind nonattainment and maintenance receptors. The EPA used CAMx photochemical source apportionment modeling to quantify the impact of emissions in specific upwind states on downwind nonattainment and maintenance receptors for 8-hour ozone. CAMx employs enhanced source apportionment techniques that track the formation and transport of ozone from specific emissions sources and calculates the contribution of sources and precursors to ozone for individual receptor locations. The benefit of the photochemical model source apportionment technique is that all modeled ozone 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.

The EPA performed nationwide, state-level ozone source apportionment modeling using the CAMx Ozone Source Apportionment Technology/Anthropogenic Precursor Culpability Analysis (OSAT/APCA) technique[124] to quantify the contribution of 2023 and 2026 base case NO_X and VOC emissions from all sources in each state to the corresponding projected ozone design values in 2023 and 2026 at air quality monitoring sites. The CAMx OSAT/APCA model run was performed for the period May 1 through September 30 using the projected future base case emissions and 2016 meteorology for this time period. As described earlier, in the source apportionment modeling the Agency tracked (*i.e.,* tagged) the amount of ozone formed from anthropogenic emissions in each state individually as well as the contributions from other sources (*e.g.,* natural emissions).

In the state-by-state source apportionment model run, the EPA tracked the ozone formed from each of the following tags:

- States—anthropogenic NO_X and VOC emissions from each state tracked individually (emissions from all anthropogenic sectors in a given state were combined);
- Biogenics—biogenic NO_X and VOC emissions domain-wide (*i.e.,* not by state);
- Boundary Concentrations—concentrations transported into the air quality modeling domain;
- Tribes—the emissions from those tribal lands for which the Agency has point source inventory data in the 2016v1 emissions modeling platform (EPA did not model the contributions from individual tribes);

[124] As part of this technique, ozone formed from reactions between biogenic VOC and NO_X with anthropogenic NO_X and VOC are assigned to the anthropogenic emissions.

• Canada and Mexico—anthropogenic emissions from sources in the portions of Canada and Mexico included in the modeling domain (the EPA did not model the contributions from Canada and Mexico separately);

• Fires—combined emissions from wild and prescribed fires domain-wide (*i.e.,* not by state); and

• Offshore—combined emissions from offshore marine vessels and offshore drilling platforms.

The contribution modeling provided contributions to ozone from anthropogenic NO_X and VOC emissions in each state, individually. The contributions to ozone from chemical reactions between biogenic NO_X and VOC emissions were modeled and assigned to the ''biogenic'' category. The contributions from wildfire and prescribed fire NO_X and VOC emissions were modeled and assigned to the ''fires'' category. That is, the contributions from the ''biogenic'' and ''fires'' categories are not assigned to individual states nor are they included in the state contributions.

For the Step 2 analysis, the EPA calculated a contribution metric that considers the average contribution on the 10 highest ozone concentration days (*i.e.,* top 10 days) in 2023. This average contribution metric is intended to provide a reasonable representation of the contribution from individual states to projected future year design values, based on modeled transport patterns and other meteorological conditions generally associated with modeled high ozone concentrations at the receptor. An average contribution metric constructed in this manner is beneficial since the magnitude of the contributions is directly related to the magnitude of the design value at each site.

The analytic steps for calculating the contribution metric for the 2023 analytic year are as follows:

(1) Calculate the 8-hour average contribution from each source tag to each monitoring site for the time period of the 8-hour daily maximum modeled concentrations in 2023;

(2) Average the contributions and average the concentrations for the top 10 modeled ozone concentration days in 2023;

(3) Divide the average contribution by the corresponding average concentration to obtain a Relative Contribution Factor (RCF) for each monitoring site;

(4) Multiply the 2023 average design values by the 2023 RCF at each site to produce the average contribution metric values in 2023.[125]

This same approach was applied to calculate contribution metric values at individual monitoring sites for 2026.[126]

The resulting contributions from each tag to each monitoring site in the U.S. for 2023 and 2026 can be found in the docket for this proposed rule. Additional details on the source apportionment modeling and the procedures for calculating contributions can be found in the AQM TSD.

The largest contribution from each state that is the subject of this rule to 8-hour ozone nonattainment and maintenance receptors in downwind states in 2023 and 2026 are provided in Table V.E.1–1 and Table V.E.1–2, respectively.

TABLE V.E.1–1—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2023 (ppb)

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
Alabama	0.88	0.71
Arizona	0.40	0.21
Arkansas	1.00	1.39
California	34.24	7.44
Colorado	0.07	0.20
Connecticut	0.01	0.21
Delaware	0.53	1.36
District of Columbia	0.04	0.07
Florida	0.16	0.15
Georgia	0.16	0.17
Idaho	0.55	0.57
Illinois	18.13	18.55
Indiana	6.60	7.10
Iowa	0.64	0.58
Kansas	0.42	0.59
Kentucky	0.83	0.88
Louisiana	5.39	7.03
Maine	0.01	0.01
Maryland	1.29	2.40
Massachusetts	0.30	0.30
Michigan	1.27	1.67
Minnesota	0.50	0.97
Mississippi	1.04	1.14
Missouri	1.08	1.66
Montana	0.08	0.11
Nebraska	0.26	0.36
Nevada	0.89	0.58
New Hampshire	0.10	0.06
New Jersey	8.85	5.79

[125] Note that a contribution metric value was not calculated for any receptor at which there were fewer than 5 days with model-predicted MDA8 ozone concentrations greater than or equal to 60 ppb in 2023. See the AQM TSD for information on those receptors that did not meet this criterion.

[126] In order to provide consistency in the contributions for 2023 and 2026, the contribution metric values for 2026 are based on the 2026 daily contributions for the same days that were used to calculate the contribution metric values for 2023.

TABLE V.E.1–1—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2023 (ppb)—Continued

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
New Mexico	0.30	0.13
New York	16.81	1.80
North Carolina	0.61	0.33
North Dakota	0.12	0.37
Ohio	1.94	1.88
Oklahoma	0.57	1.19
Oregon	1.10	1.31
Pennsylvania	6.90	0.51
Rhode Island	0.04	0.04
South Carolina	0.19	0.07
South Dakota	0.05	0.09
Tennessee	0.60	0.94
Texas	1.72	1.81
Utah	1.37	0.10
Vermont	0.02	0.02
Virginia	1.77	1.63
Washington	0.34	0.40
West Virginia	1.45	1.44
Wisconsin	0.19	2.61
Wyoming	0.81	0.19

TABLE V.E.1–2—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2026 (ppb)

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
Alabama	0.17	0.48
Arizona	0.35	0.23
Arkansas	0.62	1.30
California	33.45	4.85
Colorado	0.05	0.08
Connecticut	0.01	0.01
Delaware	0.42	0.52
District of Columbia	0.03	0.04
Florida	0.10	0.09
Georgia	0.14	0.16
Idaho	0.48	0.48
Illinois	17.81	18.14
Indiana	6.43	6.99
Iowa	0.57	0.57
Kansas	0.40	0.57
Kentucky	0.80	0.80
Louisiana	4.25	6.97
Maine	0.01	0.01
Maryland	1.11	1.23
Massachusetts	0.29	0.14
Michigan	1.03	1.58
Minnesota	0.36	0.91
Mississippi	0.36	0.90
Missouri	0.98	1.53
Montana	0.07	0.08
Nebraska	0.11	0.23
Nevada	0.81	0.51
New Hampshire	0.09	0.02
New Jersey	8.54	5.47
New Mexico	0.29	0.23
New York	16.58	11.29
North Carolina	0.38	0.54
North Dakota	0.11	0.34
Ohio	1.78	1.83
Oklahoma	0.54	0.72

TABLE V.E.1–2—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2026 (ppb)—Continued

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
Oregon	0.98	0.88
Pennsylvania	6.82	4.74
Rhode Island	0.04	0.01
South Carolina	0.15	0.17
South Dakota	0.03	0.06
Tennessee	0.25	0.34
Texas	1.61	1.70
Utah	0.95	1.18
Vermont	0.02	0.01
Virginia	1.14	1.68
Washington	0.31	0.28
West Virginia	1.23	1.35
Wisconsin	0.15	2.44
Wyoming	0.46	0.80

2. Application of Contribution Screening Threshold

The EPA evaluated the magnitude of the contributions from each upwind state to downwind nonattainment and maintenance receptors. In Step 2 of the interstate transport framework, the EPA uses an air quality screening threshold to identify upwind states that contribute to downwind ozone concentrations in amounts sufficient to ''link'' them to these to downwind nonattainment and maintenance receptors. The contributions from each state to each downwind nonattainment or maintenance receptor that were used for the Step 2 evaluation can be found in the AQM TSD.

The EPA proposes to apply an air quality screening threshold of 1 percent of the NAAQS, as it has used since the CSAPR rulemaking, including in the CSAPR Update, the Revised CSAPR Update, and numerous actions evaluating states' transport SIP submittals. EPA continues to observe that the majority of nonattainment and maintenance receptors identified at Step 1 are impacted collectively by contributions of ozone transport from numerous upwind states. Therefore, application of a uniform screening threshold allows EPA to identify upwind states that share a responsibility under the interstate transport provision to eliminate their significant contribution.

The EPA recognizes that in 2018 it issued a memorandum indicating the potential for states to use a higher threshold at Step 2 in the development of their good neighbor SIP submissions where it could be technically justified. The August 2018 memorandum stated that ''it may be reasonable and appropriate'' for states to rely on an alternative 1 ppb threshold at Step 2.[127] (The memorandum also indicated that any higher alternative threshold, such as 2 ppb, would likely not be appropriate.) Here, the EPA proposes to fulfill its role under CAA section 110(c) in promulgating FIPs to directly implement good neighbor requirements, and in this role, the EPA notes that it is authorized to exercise discretion in making policy determinations such as the appropriateness of a particular contribution threshold that would otherwise have been exercised by states. Further, as the EPA has explained in several notices proposing transport SIP disapprovals, *see, e.g.,* 87 FR 9498 and 87 FR 9510 (Feb. 22, 2022), its experience since the issuance of the August 2018 memorandum regarding use of alternative thresholds leads the Agency to now believe it may not be appropriate to continue to attempt to recognize alternative contribution thresholds at Step 2, either in the context of SIPs or FIPs.

EPA's experience since 2018 is that allowing for alternative Step 2 thresholds may be impractical or otherwise inadvisable for a number of additional policy reasons. For a regional air pollutant such as ozone, consistency in requirements and expectations across all states is essential. In the context of a FIP proposal (as much as in the context of SIP actions), the Agency now believes using different thresholds at Step 2 with respect to the 2015 ozone NAAQS raises substantial policy consistency and practical implementation concerns.[128] The availability of different thresholds at Step 2 has the potential to result in inconsistent application of good neighbor obligations. From the perspective of ensuring effective regional implementation of good neighbor obligations, the more important analysis is the evaluation of the emissions reductions needed, if any, to address a state's significant contribution after consideration of a multifactor analysis at Step 3, including a detailed evaluation that considers air quality factors and cost. Where alternative thresholds for purposes of Step 2 may be ''similar'' in terms of capturing the relative amount of upwind contribution (as described in the August 2018 memorandum), nonetheless, use of an alternative threshold would allow certain states to avoid further evaluation of potential emissions controls while other states must proceed to a Step 3 analysis. This can create significant equity and consistency problems among states.

More importantly, in promulgating FIPs to address these obligations on a nationwide scale, national ozone transport policy is not well-served by allowing for less stringent thresholds at Step 2. The EPA recognized in the August 2018 memo that there was some similarity in the amount of total upwind contribution captured (on a nationwide basis) between 1 percent and 1 ppb. However, the EPA notes that while this

[127] August 2018 memo at 4.

[128] We note that Congress has placed on the EPA a general obligation to ensure the requirements of the CAA are implemented consistently across states and regions. *See* CAA section 301(a)(2). Where the management and regulation of interstate pollution levels spanning many states is at stake, consistency in application of CAA requirements is paramount.

may be true in some sense, that is hardly a compelling basis to move to a 1 ppb threshold. Indeed, the 1 ppb threshold has the disadvantage of losing a certain amount of total upwind contribution for further evaluation at Step 3 (*e.g.,* roughly 7 percent of total upwind state contribution was lost according to the modeling underlying the August 2018 memo; [129] in EPA's updated modeling, the amount lost is roughly 5 percent). Considering the core statutory objective of ensuring elimination of *all* significant contribution to nonattainment or interference of the NAAQS in other states and the broad, regional nature of the collective contribution problem with respect to ozone, there does not appear to be a compelling policy imperative in moving to a 1 ppb threshold.

Consistency with past interstate transport actions such as CSAPR, and the CSAPR Update and Revised CSAPR Update rulemakings (which used a Step 2 threshold of 1 percent of the NAAQS for two less stringent ozone NAAQS) is also important. Continuing to use a 1 percent of NAAQS approach ensures that as the NAAQS are revised and made more stringent, an appropriate increase in stringency at Step 2 occurs, so as to ensure an appropriately larger amount of total upwind-state contribution is captured for purposes of fully addressing interstate transport for the more stringent NAAQS. EPA made this point when it originally promulgated CSAPR to address the 1997 ozone NAAQS. The Agency continues to consider this an important consideration for the more stringent 2015 ozone NAAQS. *See* 76 FR 48237–38.

Lastly, the Agency does not find it to be a good use of limited resources to attempt to further justify the use of alternative thresholds for certain states at Step 2 for purposes of the 2015 ozone NAAQS. Therefore, while EPA articulated a potential basis for recognizing the usefulness of alternative Step 2 thresholds (particularly a 1 ppb threshold) in the August 2018 memorandum, EPA's experience and further evaluation since the issuance of that memo has revealed substantial programmatic and policy difficulties in attempting to implement this approach. Depending on comment and further evaluation of this issue, the EPA may determine to rescind the 2018 memorandum in the future.

In light of the considerations above, EPA proposes using a contribution threshold of 0.70 ppb as the quantification of 1 percent of the 2015 ozone NAAQS for purposes of Step 2.

a. States That Contribute Below the Screening Threshold

Based on EPA's modeling, the contributions from each of the following states to nonattainment or maintenance-only receptors in the 2023 analytic year are below the 1% of the NAAQS threshold: Arizona, Colorado, Connecticut, the District of Columbia, Florida, Georgia, Idaho, Iowa, Kansas, Maine, Massachusetts, Montana, Nebraska, New Hampshire, New Mexico, North Carolina, North Dakota, Rhode Island, South Carolina, South Dakota, Vermont, and Washington. The EPA has already approved many of these states' SIP submittals or is in the process of taking action to approve them. Because the contributions from these states to projected downwind air quality problems are below the screening threshold in the current modeling, these states are not within the scope of this proposed rule. Additionally, the EPA has made proposed or final determinations that two states outside the modeling domain for the air quality modeling analyzed in this proposed rulemaking—Hawaii [130] and Alaska [131]—do not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any other state.

a. States That Contribute at or Above the Screening Threshold

Based on the maximum downwind contributions in Table V.E.1–1, the Step 2 analysis identifies that the following 22 states contribute at or above the 0.70 ppb threshold to downwind nonattainment receptors in 2023: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oregon, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wyoming. Based on the maximum downwind contributions in Table V.E.1–1, the following 23 states contribute at or above the 0.70 ppb threshold to downwind maintenance-only receptors in 2023: Alabama, Arkansas, California, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Ohio, Oklahoma, Oregon, Tennessee, Texas, Virginia, West Virginia, and Wisconsin. The levels of contribution between each of these linked upwind states and downwind nonattainment receptors and maintenance-only receptors are provided in the AQM TSD.

Among the linked states are several western states—California, Nevada, Oregon, Utah, and Wyoming. While the EPA has not previously included action on linked western states in its prior CSAPR rulemakings, the EPA has consistently applied the 4-step framework in evaluating good neighbor obligations from these states. On a case-by-case basis, the EPA has found in some instances with respect to the 2008 ozone NAAQS that a unique consideration has warranted approval of a linked western state's good neighbor SIP submittal without concluding that additional emissions reductions are required at Step 3 of the framework.[132] The EPA has also explained in prior actions that its air quality modeling is reliable for assessing downwind air quality problems and ozone transport contributions from upwind states throughout the nationwide modeling domain.[133]

In EPA's current analysis, the EPA finds that for one linked state—Oregon—the same considerations that led it to approve another state's SIP submission, Arizona's, for the 2008 ozone NAAQS apply to Oregon's circumstances for the 2015 ozone NAAQS. As explained in the following section, the EPA therefore proposes to affirm its prior approval of Oregon's good neighbor SIP submission for the 2015 ozone NAAQS. For the remaining western states included in this proposed rule, EPA's modeling supports a conclusion that these states are linked above the contribution threshold to identified ozone transport receptors in other states, and therefore, consistent with the treatment of all other states within the modeling domain, the EPA proposes to proceed to evaluate these states for a determination of ''significant contribution'' at Step 3.

In conclusion, as described above, states with contributions that equal or exceed 1 percent of the NAAQS to either nonattainment or maintenance receptors are identified as ''linked'' at Step 2 of the good neighbor framework and warrant further analysis for significant contribution to nonattainment or interference with

[129] *See* August 2018 memo, at 4.

[130] The EPA proposed to approve Hawaii's 2015 ozone transport SIP on September 28, 2021. *See* 86 FR 53571.

[131] The EPA approved Alaska's 2015 ozone transport SIP on December 18, 2019. *See* 84 FR 69331.

[132] *See* interstate transport approval actions under the 2008 ozone NAAQS for Arizona, California, and Wyoming at 81 FR 36179 (June 6, 2016), 83 FR 65093 (December 19, 2018), and 84 FR 14270 (April 10, 2019), respectively.

[133] *See* 81 FR 71991 (October 19, 2016), 82 FR 9155 (February 3, 2017).

maintenance under Step 3. The EPA proposes that the following 27 States are linked at Step 2 in 2023: Alabama, Arkansas, California, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming. In addition, the EPA proposes that the following 24 States are linked at Step 2 in 2026: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming. Three states, Alabama, Delaware, and Tennessee, that were linked in 2023 are not linked in 2026 because the receptor(s) to which each state was linked in 2023 are projected to attain by 2026.

F. Treatment of Certain Receptors in California and Implications for Oregon's Good Neighbor Obligations for the 2015 Ozone NAAQS

The EPA previously approved Oregon's September 25, 2018 transport SIP submittal for the 2015 ozone NAAQS on May 17, 2019 (84 FR 22376), because in an earlier round of modeling Oregon was not projected to contribute above 1 percent of the NAAQS to any downwind receptors. In EPA's updated modeling, Oregon is linked above the 1 percent of NAAQS threshold to several monitoring sites in California that would generally meet EPA's definition of nonattainment or maintenance ''receptors'' at Step 1.[134] However, EPA's analysis of the nature of the air quality problem at these monitoring sites leads EPA to propose a determination that these monitoring sites should not be treated as receptors for purposes of determining interstate transport obligations of upwind states under CAA section 110(a)(2)(D)(i)(I). EPA reaches this conclusion at Step 1 of its four-step framework.

The EPA previously made a similar assessment of the nature of certain other monitoring sites in California in approving Arizona's 2008 ozone NAAQS transport SIP submittal.[135] There, the EPA noted that a ''factor [. . .] relevant to determining the nature of a projected receptor's interstate transport problem is the magnitude of ozone attributable to transport from all upwind states collectively contributing to the air quality problem.'' [136] The EPA observed that only one upwind state (Arizona) was linked above 1 percent of the 2008 ozone NAAQS to the two relevant monitoring sites in California, and the cumulative ozone contribution from all upwind states to those sites was 2.5 percent and 4.4 percent of the total ozone, respectively. The EPA determined the size of those cumulative upwind contributions was ''negligible, particularly when compared to the relatively large contributions from upwind states in the East or in certain other areas of the West.'' [137] In that action, the EPA concluded the two California sites to which Arizona was linked should not be treated as receptors for the purposes of determining Good Neighbor obligations for the 2008 ozone NAAQS.[138]

The EPA proposes to make a similar finding for the monitoring sites in California otherwise projected in its current modeling to be ''receptors'' for the 2015 ozone NAAQS and to which Oregon is linked. The highest percent of the total cumulative upwind ozone contribution to any of these sites is 2.8 percent.[139] This is lower than the largest transport contribution relative to total ozone at the California sites identified in EPA's approval of Arizona's 2008 ozone transport SIP (4.4 percent).[140] Further, as was the case for the sites in California analyzed in EPA's Arizona action, the identified sites in California each have only one upwind state contributing above 1 percent of the NAAQS to them (Oregon). These monitoring sites in California are overwhelmingly impacted by in-state emissions to a degree not comparable with any other identified nonattainment or maintenance-only receptors in the country.

The EPA proposes to find that these monitoring sites should not be considered receptors for the purpose of assessing 2015 ozone NAAQS interstate transport obligations. The EPA is not proposing a different contribution threshold at Step 2 for Western states or receptors, nor does the EPA reach its conclusion based on any evaluation at Step 3 of emissions reduction opportunities in Oregon.

As a consequence of this proposed finding, the EPA continues to find that ozone-precursor emissions from Oregon do not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any downwind state, because the total collective upwind state ozone contribution to the California monitoring sites is extremely low compared to the air quality problems typically addressed under the good neighbor provision. Therefore, the EPA is not proposing any change in this action to its prior approval of Oregon's SIP. The EPA is not proposing any new FIP requirements and is not proposing to require reductions from new or existing EGU or non-EGU sources in Oregon in this action. If, however, EPA were not to finalize this proposed approach, then EPA anticipates that it would apply the same control strategies in Oregon as applied in all other linked upwind states, as discussed in Sections VI and VII of this proposed rule. EPA requests public comment on its approach to characterizing the nature of the interstate transport problem at the California monitoring sites at issue and the consequent approach to assessing Oregon's good neighbor obligations.

VI. Quantifying Upwind-State NO_X Emissions Reduction Potential To Reduce Interstate Ozone Transport for the 2015 Ozone NAAQS

A. The Multi-Factor Test for Determining Significant Contribution

This section describes EPA's methodology at Step 3 of the 4-step framework for identifying upwind emissions that constitute ''significant'' contribution for the states subject to this proposed rule and focuses on the 26 states with FIP requirements identified in the sections above. Following the existing framework as applied in all of the prior CSAPR rulemakings, EPA's assessment of linked upwind state emissions is based primarily on analysis of several alternative levels of NO_X emissions control stringency applied uniformly across all of the linked states. The analysis includes assessment of non-EGU stationary sources in addition to EGU sources in the linked upwind states.

The EPA applies a multi-factor test—the same multi-factor test that was used in CSAPR, the CSAPR Update, and the Revised CSAPR Update [141]—to evaluate increasing levels of uniform NO_X control stringency. The multi-factor test, which is central to EPA's Step 3

[134] Monitors are listed in the AQM TSD included in the docket for this rulemaking. While EPA is providing information about cumulative upwind contribution to the California monitors, the Agency does not consider these monitors as ozone transport receptors in this proposal.

[135] 81 FR 15200 (March 22, 2016) (proposal); 81 FR 31513 (May 19, 2016) (final rule).

[136] 81 FR at 15203.

[137] *Id.*

[138] *Id.*

[139] See Air Quality Modeling TSDin the docket for this action.

[140] 81 FR at 15203; 81 FR 31513.

[141] *See* CSAPR, Final Rule, 76 FR 48208 (August 8, 2011).

quantification of significant contribution, considers cost, available emissions reductions, downwind air quality impacts, and other factors to determine the appropriate level of uniform NO_X control stringency that would eliminate significant contribution to downwind nonattainment or maintenance receptors. The selection of a uniform level of NO_X emissions control stringency across all of the linked states, reflected as a representative cost per ton of emissions reduction (or a weighted average cost per ton in the case of EPA's non-EGU and EGU analysis for 2026 mitigation measures), also serves to apportion the reduction responsibility among collectively contributing upwind states. This approach to quantifying upwind state emission-reduction obligations using uniform cost was reviewed by the Supreme Court in *EME Homer City Generation,* which held that using such an approach to apportion emissions reduction responsibilities among upwind states that are collectively responsible for downwind air quality impacts ''is an efficient and equitable solution to the allocation problem the Good Neighbor Provision requires the Agency to address.'' 572 U.S. at 519.

There are four stages in developing the multi-factor test: (1) Identify levels of uniform NO_X control stringency; (2) evaluate potential NO_X emissions reductions associated with each identified level of uniform control stringency; (3) assess air quality improvements at downwind receptors for each level of uniform control stringency; and (4) select a level of control stringency considering the identified cost, available NO_X emissions reductions, and downwind air quality impacts, while also ensuring that emissions reductions do not unnecessarily over-control relative to the contribution threshold or downwind air quality.

As mentioned in Section IV.A.2 of this proposed rule, commenters on previous ozone transport rules have suggested that the EPA should regulate VOCs as an ozone precursor. For this proposed rule, the EPA examined the results of the contribution modeling performed for this rule to identify the portion of the ozone contribution attributable to anthropogenic NO_X emissions versus VOC emissions from each linked upwind state to each downwind receptor. Of the total upwind-downwind linkages in 2023, the contributions from NO_X emissions comprise 80 percent or more of the total anthropogenic contribution at the vast majority of linkages (136 out of 140 total). Across all receptors, the contribution from NO_X emissions ranges from 77 percent to 99 percent of the total anthropogenic contribution. This review of the portion of the ozone contribution attributable to anthropogenic NO_X emissions versus VOC emissions from each linked upwind state leads the Agency to conclude that the vast majority of the downwind air quality areas addressed by the proposed rule under are primarily NO_X-limited, rather than VOC-limited. Therefore, the EPA is proposing to determine that the regulation of VOCs as an ozone precursor is not necessary to eliminate significant contribution of ozone transport to downwind areas in this proposed rule. The remainder of this section focuses on EPA's strategy for reducing regional-scale transport of ozone by targeting NO_X emissions from stationary sources to achieve the most effective reductions of ozone transport over the geography of the affected downwind areas.

For both EGUs and non-EGUs, Section VI.B of this proposed rule describes the available NO_X emissions controls that the EPA evaluated for this proposed rule and their representative cost levels (in 2016$). Section VI.C of this proposed rule discusses EPA's application of that information to assess emissions reduction potential of the identified control stringencies. Finally, Section VI.D of this proposed rule describes EPA's assessment of associated air quality impacts and EPA's subsequent identification of appropriate control stringencies considering the key relevant factors (cost, available emissions reductions, and downwind air quality impacts).

This multi-factor approach is consistent with EPA's approach in prior transport actions, such as CSAPR. In addition, as was evaluated in the CSAPR Update and Revised CSAPR Update, the EPA evaluated possible over-control by examining whether an upwind state is linked solely to downwind air quality problems that could have been resolved at a lesser threshold of control stringency and whether an upwind state could reduce its emissions below the 1 percent air quality contribution threshold at a lesser threshold of control stringency. This analysis is described in Section VI.D of this proposed rule.

Finally, while the EPA has evaluated potential emissions reductions from non-EGU sources in prior rules, this is the first action for which the EPA is proposing non-EGU emissions reductions within the context of its 4-step interstate transport framework. The EPA applies its multi-factor test to non-EGUs and independently evaluates non-EGU industries in a consistent but parallel track to its Step 3 assessment for EGUs. This is consistent with the parallel assessment approach taken for EGUs and non-EGUs in the Revised CSAPR Update. Following the conclusions of the EGU and non-EGU multi-factor tests, the identified reductions for EGUs and non-EGUs are combined and collectively analyzed to assess their effects on downwind air quality and whether the rule achieves a full remedy to ''significant contribution'' while avoiding over-control.

In order to ensure that this rule implements a full remedy for the elimination of significant contribution from upwind states, the EPA has reviewed available information on all major industrial source sectors in the upwind states. This analysis leads the EPA to propose that both EGUs and certain large sources in several specific industrial categories should be evaluated for emissions control opportunities. As discussed in the sections that follow, the EPA proposes that for both EGUs and the selected non-EGU source categories, there are impactful emissions reduction opportunities available at reasonable cost-effectiveness thresholds. As in the Revised CSAPR Update, the EPA examines EGUs and non-EGUs in this section on consistent but distinct, parallel tracks due to differences stemming from the unique characteristics of the power sector compared to other industrial source categories. Since the NO_X SIP Call, EGUs have consistently been regulated under ozone transport rules. These units operate in a coordinated manner across a highly interconnected electrical grid. Their configuration and emissions control strategies are relatively homogenous, and their emissions levels and emissions control opportunities are generally very well understood due to longstanding monitoring and data-reporting requirements. Non-EGU sources, by contrast, are relatively heterogeneous, even within a single industrial category, and have far greater variation in existing emissions control requirements, emissions levels, and technologies to reduce emissions. In general, despite these differences, the information available for this proposal indicates that both EGUs and certain non-EGU categories have available cost-effective NO_X emissions reduction opportunities at relatively commensurate cost per ton levels, and these emissions reductions will make a meaningful improvement in air quality at the downwind receptors. Section VI.B.2 of this proposed rule describes EPA's process for selecting specific Tier I and Tier II non-EGU source categories included in this proposed rulemaking.

The EPA notes that its Step 3 analysis does not assess emissions reduction opportunities from mobile sources. The EPA continues to believe that title II of the CAA provides the primary authority and process for reducing ozone-precursor pollutants from mobile sources. EPA's federal mobile source programs have delivered and are projected to continue to deliver substantial nationwide reductions in both VOCs and NO_X emissions; these reductions are factored into the Agency's assessment of air quality and contributions at Steps 1 and 2. Further, states are generally preempted from regulating new vehicles and engines with certain exceptions, and therefore a question exists regarding EPA's authority to address such emissions when regulating in place of the states under CAA section 110(c). *See generally* CAA sections 209, 177. *See also* 86 FR 23099. As noted earlier, the EPA accounted for mobile source emissions reductions resulting from other federally enforceable regulatory programs in the development of emissions inventories used to support analysis for this proposed rulemaking, and the EPA does not evaluate any mobile source control measures in its Step 3 evaluation in this proposal.[142] For further discussion of EPA's existing and ongoing mobile source measures, *see* Section VI.B.4 of this proposed rule.

B. Identifying Control Stringency Levels

1. EGU NO_X Mitigation Strategies

In identifying levels of uniform control stringency for EGUs, the EPA assessed the same NO_X emissions controls that the Agency analyzed in the CSAPR Update and the Revised CSAPR Update, all of which are considered to be widely available in this sector: (1) Fully operating existing SCR, including both optimizing NO_X removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art NO_X combustion controls; (3) fully operating existing SNCRs, including both optimizing NO_X removal by existing operational SNCRs and turning on and optimizing existing idled SNCRs; (4) installing new SNCRs; (5) installing new SCRs; and (6) generation shifting (*i.e.,* emission reductions anticipated to occur from generation shifting from higher to lower emitting units at each of these stringency levels). For the reasons explained in the EGU NO_X Mitigation Strategies Proposed Rule TSD included in the docket for this proposed rule, the EPA determined that for the regional, multi-state scale of this rulemaking, only EGU NO_X emissions controls 1, 3, and 6 are possible for the 2023 ozone season (fully operating existing SCRs and SNCRs, and associated generation shifting). The EPA finds that it is not possible to install state-of-the-art NO_X combustion controls by the 2023 ozone season on a regional scale for Group 3 states not covered under the Revised CSAPR Rule. The EPA also determined that state-of-the-art NO_X combustion controls at EGUs are available by the beginning of the 2024 ozone season. All cost values discussed below for EGUs are in 2016 dollars.

a. Optimizing Existing SCRs

Optimizing (*i.e.,* turning on idled or improving operation of partially operating) existing SCRs can substantially reduce EGU NO_X emissions quickly, using investments that have already been made in pollution control technologies. With the promulgation of the CSAPR Update and the Revised CSAPR Update, most operators in the covered states improved their SCR performance and have continued to maintain that level of improved operation. However, this optimized SCR performance was not universal and not always sustained. Between 2017 and 2020, as the CSAPR Update ozone-season NO_X allowance price declined, NO_X emissions rates at some SCR-controlled EGUs increased. For example, power sector data from 2019 revealed that, in some cases, operating units had SCR controls that had been idled or were operating partially, and therefore suggested that there remained emissions reduction potential through optimization.[143] The EPA determined that optimizing all of these remaining SCRs in the 12 linked states for the Revised CSAPR Update was a readily available approach for EGUs to reduce NO_X emissions. This emissions reduction measure is currently available at EGUs across the broader geography affected in this proposed rulemaking (including in states not previously affected by the Revised CSAPR Update). The EPA thus proposes that SCR optimization, of both idled and partially operating controls, is a viable mitigation strategy for the 2023 ozone season.

The EPA estimates a representative marginal cost of optimizing SCR controls to be approximately $1,600 per ton, consistent with its estimation in the Revised CSAPR Update for this technology. EPA's EGU NO_X Mitigation Strategies Proposed Rule TSD for this rule describes a range of cost estimates for this technology noting that the costs are frequently lower than—and for the majority of EGUs, significantly lower than—this representative marginal cost. While the costs of optimizing existing, operational SCRs include only variable costs, the cost of optimizing SCR units that are currently idled considers both variable and fixed costs of returning the control into service. Variable and fixed costs include labor, maintenance and repair, parasitic load, and ammonia or urea for use as a NO_X reduction reagent in SCR systems. Depending on a unit's control operating status, the representative cost at the 90th percentile unit (among the relevant fleet of coal units with SCR covered in this rulemaking) ranges between $900 and $1,700 per ton. The EPA performed an in-depth cost assessment for all coal-fired units with SCRs and found that for the subset of SCRs that are already partially operating, the cost of optimizing is often much lower than $1,600 per ton and is often under $900 per ton. The EPA anticipates the vast majority of realized cost for compliance with this strategy to be better reflected by the $900 per ton end of that range (reflecting the 90th percentile of EGUs optimizing SCRs that are already partially operating) because this circumstance is considerably more common than EGUs that have ceased operating their SCR. EPA's analysis of this emissions control is informed by the latest engineering modeling equations used in EPA's IPM platform. These cost and performance equations were recently updated in the summer of 2021. The description and development of the equations are documented in EGU NO_X Mitigation Strategies Proposed Rule TSD and accompanying documents.[144] They are also

[142] The EPA recognizes that mechanisms exist under title I of the CAA that allow for the regulation of the use and operation of mobile sources to reduce ozone-precursor emissions. These include motor vehicle inspection and maintenance (I/M) programs, gasoline vapor recovery, clean-fuel vehicle programs, transportation control programs, and vehicle miles traveled programs. *See, e.g.,* CAA sections 182(b)(3), 182(b)(4), 182(c)(3), 182(c)(4), 182(c)(5), 182(d)(1), 182(e)(3), and 182(e)(4). The EPA views these programs as most effective and appropriate in the context of the planning requirements applicable to designated nonattainment areas.

[143] *See* ''Ozone Season Data 2018 vs. 2019'' and ''Coal-fired Characteristics and Controls'' at *https://www.epa.gov/airmarkets/power-plant-data-highlights#OzoneSeason.*

[144] The CSAPR Update estimated $1,400 per ton as a representative cost of turning on idled SCR controls. EPA used the same costing methodology

Continued

implemented in an interactive spreadsheet tool called the Retrofit Cost Analyzer and applied to all units in the fleet. These materials are available in the docket for this proposal.

The EPA is using the same methodology to identify SCR performance as it did in the Revised CSAPR Update. To estimate EGU NO_X reduction potential from optimizing, the EPA considers the difference between the non-optimized NO_X emissions rates and an achievable operating and optimized SCR NO_X emissions rate. To determine this rate, EPA evaluated nationwide coal-fired EGU NO_X ozone season emissions data from 2009 through 2019 and calculated an average NO_X ozone season emissions rate across the fleet of coal-fired EGUs with SCR for each of these eleven years. The EPA found it prudent to not consider the lowest or second-lowest ozone season NO_X emissions rates, which may reflect SCR systems that have all new components (*e.g.,* new layers of catalyst). Data from these systems are potentially not representative of ongoing achievable NO_X emissions rates considering broken-in components and routine maintenance schedules. To identify the potential reductions from SCR optimization in this proposed rule, the EPA followed the same methodology as the Revised CSAPR Update. Considering the emissions data over the full time period from 2009–2019 data results in a third-best rate of 0.079 pounds NO_X per million British thermal units (lb/mmBtu).[145] Therefore, consistent with the Revised CSAPR Update, where EPA identified 0.08 lb/mmBtu as a reasonable level of performance for units with optimized SCR, the EPA proposes a rate of 0.08 lb/mmBtu as the optimized rate for this rule. The EPA notes that half of the SCR-controlled EGUs achieved a NO_X emissions rate of 0.064 lbs/mmBtu or less over their third-best entire ozone season. Moreover, for the SCR-controlled coal units that the EPA identified as having a 2021 emissions rate greater than 0.08 lb/mmBtu, the EPA verified that in prior years, the majority (more than 90 percent) of these same units had demonstrated and achieved a NO_X emissions rate of 0.08 lb/mmBtu or less on a seasonal or monthly basis. This further supports EPA's determination that 0.08 lb/mmBtu reflects a reasonable emissions rate for representing SCR optimization at coal steam units in identifying uniform control stringency. This emissions rate assumption of 0.08 lb/mmBtu reflects what those units would achieve on average when optimized, recognizing that individual units may achieve lower or higher rates based on unit-specific configuration and dispatch patterns. Units historically performing at, or better, than this rate of 0.08 lb/mmBtu are assumed to continue to operate at that prior performance level.

Given the magnitude and duration of the air quality problems addressed by this rulemaking, the EPA also applied the same methodology to identify a reasonable level of performance for optimizing existing SCRs at oil- and gas-fired steam units and simple cycle units (for which EPA determined that a 0.03 lb/mmBtu emissions rate reflected SCR optimization) as well as at combined-cycle units (for which the EPA determined that a 0.012 lb/mmBtu emissions rate reflected SCR optimization).

The EPA evaluated the feasibility of optimizing idled SCRs for the 2023 ozone season. Based on industry past practice, the EPA determined that idled controls can be restored to operation quickly (*i.e.,* in less than 2 months). This timeframe is informed by many electric utilities' previous long-standing practice of utilizing SCRs to reduce EGU NO_X emissions during the ozone season while putting the systems into protective lay-up during the non-ozone season months. For example, this was the long-standing practice of many EGUs that used SCR systems for compliance with the NO_X Budget Trading Program. It was quite typical for SCRs to be turned off following the September 30 end of the ozone season control period. These controls would then be put into protective lay-up for several months of non-use before being returned to operation by May 1 of the following ozone season.[146] Therefore, the EPA believes that optimization of existing SCRs is possible for the portion of the 2023 ozone season covered under this proposed rule.

The vast majority of SCR-controlled units (nationwide and in the 25 linked states for which EPA is issuing a FIP for EGUs) are already partially operating these controls during the ozone season based on reported 2021 emissions rates. Existing SCRs operating at partial capacity still provide functioning, maintained systems that may only require an increased chemical reagent feed rate (*i.e.,* ammonia or urea) up to their design potential and catalyst maintenance for mitigating NO_X emissions; such units may require increased frequency or quantity of deliveries, which can be accomplished within a few weeks. In many cases, EGUs with SCR have historically achieved more efficient NO_X removal rates than their current performance and can therefore simply revert to earlier operation and maintenance plans that achieved demonstrably better SCR performance.

In the 12 states subject to this control stringency in the Revised CSAPR Update, the EPA observed significant immediate-term improvements in SCR performance in the first ozone season following finalization of that rule, as evidenced in particular by the sharp drop in emissions rate at Miami Fort unit 7 (*see* EGU NO_X Mitigation Strategies Proposed Rule TSD). Such empirical data further illustrates the viability of this mitigation strategy for the 2023 control period in response to this rule.

b. Installing State-of-the-Art NO_X Combustion Controls

The EPA estimates that the representative cost of installing state-of-the-art combustion controls is comparable to, if not notably less than, the estimated cost of optimizing existing SCR (represented by $1,600 per ton). State-of-the-art combustion controls such as low-NO_X burners (LNB) and over-fire air (OFA) can be installed or updated quickly and can substantially reduce EGU NO_X emissions. Nationwide, approximately 99 percent of coal-fired EGU capacity greater than 25 MW is equipped with some form of combustion control; however, the control configuration or corresponding emissions rates at a small portion of those units (including units in those states covered in this action) indicate they do not currently have state-of-the-

while updating for input cost increases (*e.g.,* urea reagent) to arrive at $1,600 per ton in the final Revised CSAPR Update (while also updating from 2011 dollars to 2016 dollars).

[145] The EPA notes that updating the inventory of units to reflect recent retirements and most recent year data (*e.g.,* 2009–2021) would provide a lower value of 0.071 lb/mmBtu. This value is lower than the 0.08 pounds per million British thermal units (lb/mmBtu) assessed in the Revised CSAPR Update as it reflects 2020 data and also excludes the SCR performance of since retired coal units with SCRs. However, 2020 was an outlier year (related to pandemic impacts on the electric grid). Additionally, a unit's retirement does not obviate the usefulness of its data for assessing technology performance. Consequently, EPA is proposing the same value of 0.08 lb/mmBtu identified at the time of the final Revised CSAPR Update Rule.

[146] In the 22-state CSAPR Update region, 2005 EGU NO_X emissions data suggest that 125 EGUs operated SCR systems in the summer ozone season while idling these controls for the remaining 7 non-ozone season months of the year. Units with SCR were identified as those with 2005 ozone season average NO_X rates that were less than 0.12 lbs/mmBtu and 2005 average non-ozone season NO_X emissions rates that exceeded 0.12 lbs/mmBtu and where the average non-ozone season NO_X rate was more than double the ozone season rate.

art combustion control technology. As described in the Revised CSAPR Update, the Agency updated its NO_X emissions rates for upgrading existing combustion controls to state-of-the-art combustion control. The EPA is maintaining its determination that NO_X emissions rates of 0.146 to 0.199 lbs/mmBtu can be achieved on average depending on the unit's boiler configuration,[147] and, once installed, reduce NO_X emissions at all times of EGU operation.

These assumptions are consistent with the Revised CSAPR Update and they are further discussed in the EGU NO_X Mitigation Strategies Proposed Rule TSD. In particular, the EPA proposes to apply the 0.199 lb/mmBtu emissions rate assumption for all unit types, consistent with its determination in the Revised CSAPR Update. The average emissions rate assumption derived from EPA's analysis would be 0.199 lb/mmBtu for combustion controls on dry bottom wall fired units and 0.146 lb/mmBtu for tangentially fired units. However, stakeholders have provided detailed analysis of how other unit considerations, such as coal rank, can result in large deviations from what has been historically demonstrated with this combustion control technology. Based on this and EPA's review of historical performance data for tangentially-fired units by coal rank with state-of-the-art combustion controls, the EPA determined in the final Revised CSAPR Update that it was appropriate to use the 0.199 lb/mmBtu rate for both tangentially and wall-fired units when estimating reduction potential for units with combustion control upgrade potential.

The EPA proposes to continue that approach in this action. Many of the likely impacted units burn bituminous coal, and the 0.146 lb/mmBtu nationwide average for tangentially-fired (inclusive of subbituminous units) appears to be below the demonstrated emissions rate of state-of-the-art combustion controls for bituminous coal units of this boiler type. Therefore, EPA's assumption of 0.199 lb/mmBtu for combustion controls is robust to current and future coal choice at a unit.

In promulgating CSAPR, the EPA examined the feasibility of installing combustion controls, and found that industry had demonstrated ability to install state-of-the-art LNB controls on a large unit (800 MW) in under six months when including the pre-installation phases (design, order placement, fabrication, and delivery).[148] In prior rules, the EPA has documented its own assessment of combustion control timing installation as well as evaluated comments it received regarding installation of combustion controls from the Institute of Clean Air Companies.[149] Those comments provided information on the equipment and typical installation time frame for new combustion controls, accounting for all steps. Commenters noted that it generally takes between 6–8 months on a typical boiler—covering the time through bid evaluation through start-up of the technology. The deployment schedule is repeated here as:

- 4–8 weeks—bid evaluation and negotiation
- 4–6 weeks—engineering and completion of engineering drawings
- 2 weeks—drawing review and approval from user
- 10–12 weeks—fabrication of equipment and shipping to end user site
- 2–3 weeks—installation at end user site
- 1 week—commissioning and start-up of technology

Given the above timeframe of approximately 6 to 8 months to complete combustion control installation in the region, the EPA is proposing to determine that installation of state-of-the-art combustion controls is a readily available approach for EGUs to reduce NO_X emissions by the start of the 2024 ozone season. More details on these analyses can be found in the EGU NO_X Mitigation Strategies Proposed Rule TSD.

The cost of installing state-of-the-art combustion controls per ton of NO_X reduced is dependent on the combustion control type and unit type. The EPA estimates the cost per ton of state-of-the-art combustion controls to be $400 per ton to $1,200 per ton of NO_X removed using a representative capacity factor of 85 percent. This cost fits well within EPA's representative cost threshold observed for SCR optimization and combustion controls (of $1,600 per ton) which would accommodate combustion control upgrade even under scenarios where a lower capacity factor is assumed. *See* the EGU NO_X Mitigation Strategies Proposed Rule TSD for additional details.

c. Optimizing Already Operating SNCRs or Turning on Idled Existing SNCRs

Optimizing already operating SNCRs or turning on idled existing SNCRs can also reduce EGU NO_X emissions quickly, using investments in pollution control technologies that have already been made. Compared to no post-combustion controls on a unit, SNCRs can achieve a 25 percent reduction on average in EGU NO_X emissions (with sufficient reagent). They are less capital intensive but less efficient at NO_X removal than SCRs. These controls are in use to some degree across the U.S. power sector. In the 25 linked states identified in this proposed rule with identified EGU reductions in their proposed FIP, approximately 11 percent of coal-fired EGU capacity is equipped with SNCR.[150] Recent power sector data suggest that, in some cases, SNCR controls have been operating less in 2021 relative to performance in prior years.

The EPA determined that optimizing already operating SNCRs or turning on idled SNCRs is an available approach for EGUs to reduce NO_X emissions, has similar implementation timing to restarting idled SCR controls (less than 2 months for a given unit), and therefore could be implemented in time for the 2023 ozone season. The EPA is proposing implementation of this emissions control technology beginning in the 2023 ozone season.

Using an updated data assessment using the Retrofit Cost Analyzer described in the EGU NO_X Mitigation Strategies Proposed TSD, the EPA estimates a representative cost of optimizing SNCR ranging from approximately $1,800 per ton (for partially operating SNCRs) to $3,900 per ton (for idled SNCRs). For existing SNCRs that have been idled, unit operators may need to restart payment of some fixed and variable operating costs including labor, maintenance and repair, parasitic load, and ammonia or urea. The EPA determined that the majority of units with existing SNCR optimization potential were already partially operating their controls. Therefore, the EPA proposes a representative cost of $1,800 per ton for SNCR optimization as this value best reflects the circumstances of the majority of the affected EGUs with SNCR.

[147] Details of EPA's assessment of state-of-the-art NO_X combustion controls are provided in the EGU NO_X Mitigation Strategies Proposed Rule TSD.

[148] The EPA finds that, generally, the installation phase of state-of-the-art combustion control upgrades—on a single-unit basis—can be as little as 4 weeks to install with a scheduled outage (not including the pre-installation phases such as permitting, design, order, fabrication, and delivery) and as little as 6 months considering all implementation phases.

[149] EPA–HQ–OAR–2015–0500–0093.

[150] *https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6.*

d. Installing New SNCRs

Like existing SNCRs, new SNCR retrofit is also available to power plants and can achieve a 25% NO_X reduction on average. The EPA evaluated potential emissions reductions and associated costs from retrofitting EGUs with new SNCR post-combustion controls at steam units lacking such controls. New SNCR technology provides owners with a relatively less capital-intensive option for reducing NO_X emissions compared to new SCR technology, albeit at the expense of higher operating costs on a per-ton basis and less total emissions reduction potential. SNCR is more widely observed on relatively smaller coal units given its low capital/variable cost ratio. The average capacity of a coal unit with SNCR is half the size of the average capacity of coal unit with SCR.[151] Given these observations, the EPA identifies this technology as an emissions reduction measure for coal units less than 100 MW lacking post-combustion NO_X control technology. As described in the EGU NO_X Mitigation Strategies Proposed Rule TSD, the EPA estimated that $6,700 per ton reflects a representative SNCR retrofit cost level for a majority of these units.

SNCR installations generally have shorter project installation timeframes relative to other post-combustion controls. The time for engineering review, contract award, fabrication, delivery, and hookup is as little as 16 months including pre-contract award steps for an individual power plant installing controls on more than one boiler. This timeframe would mean the control would be available for the start of the 2024 or 2025 ozone season (*i.e.,* calculating 16 months from when this proposal is finalized). However, SNCR retrofits have less pollution reduction potential than alternative post-combustion controls such as SCRs. The EPA is not identifying SNCR technology as a strategy for larger steam units due to this lower removal efficiency and the empirical evidence of existing sources preferring the more efficient SCRs. Even for those smaller units less than 100 MWs identified as potential candidates for this technology, the EPA does not want to preclude those units from pursuing more advanced pollution controls. Therefore, the EPA also considers the point in time when all types of post-combustion control installation could be achieved—*i.e.,* by the 2026 ozone season. SNCR installation share similar implementation steps with and also need to account for the same regional factors as SCR installations.[152] Therefore, while the EPA is determining that at least 16 months would be needed to complete all necessary steps of SNCR development and installation at the EGUs not currently equipped with SNCRs in the 25 states linked to downwind receptors in this proposed rule, the EPA notes that the Agency evaluated SNCR as a post-combustion control technology collectively with SCR and estimated installation timing considerations of 36 months. EPA believes its proposed collective timing considerations for post-combustion control retrofit (SNCR and SCR) are practicable given that the preferable capital-intensive investment retrofit decision would be highly unit-specific and subject to a unit's compliance strategy choices with respect to multiple regulatory requirements.

Nonetheless, the EPA is requesting comment on whether post-combustion control timing assumptions (SCR and SNCR) should be decoupled, which would result in the EPA using the 16-month time frame specific to SNCR installation to estimate the first year in which these reductions are available. The EPA is only identifying this technology for units less than 100 MW (a size at which units rarely implement SCR retrofit technology). In effect, decoupling these timing assumptions would move the reductions associated with this control stringency from beginning in the 2026 ozone season to beginning in the 2024 or 2025 ozone season (depending on when this proposal is finalized). This would impact approximately 1,000 tons of identified reduction potential related to SNCR retrofit.

e. Installing New SCRs

Selective Catalytic Reduction (SCR) controls already exist on approximately 60% of the coal fleet in the linked states that would be subject to a FIP in this proposed rulemaking. Nearly every pulverized coal unit larger than 100 MW built in the last 30 years has installed this control, which is generally required for Best Available Control Technology (BACT) purposes. Other than circulating fluidized bed coal units which can achieve a comparably low emissions rate without this technology, the EPA identifies this emissions reduction measure for coal steam units greater than or equal to 100 MW. SCR is widely available for existing coal units of this size and can provide significant emissions reduction potential, with removal efficiencies of up to 90 percent. The EPA limited its consideration of SCR technology to steam units greater than or equal to 100 MW. The costs for retrofitting a plant smaller than 100 MW with SCR increase rapidly due to a lack of economy of scale.[153]

The amount of time needed to retrofit an EGU with new SCR extends beyond the 2023 ozone season. The EPA proposes that a strategy of retrofitting new SCR on a fleetwide, regional scale is available by, but no earlier than, the 2026 ozone season. Similar to the SNCR retrofits discussed above, the EPA evaluated potential emissions reductions and associated costs from this control technology, as well as the impacts and need for this emissions control strategy, at the earliest point in time when their installation could be achieved. In the past, the EPA has found the amount of time to retrofit a single EGU with new SCR, depending on the regulatory program under which such control may be required, may vary between approximately 2 and 4 years depending on site-specific engineering considerations and on the number of installations being considered. This includes steps for engineering review, construction permit, operating permit, and control technology installation (including fabrication, pre hookup, control hookup, and testing). EPA's assessment of installation procedures suggests as little as 21 months may be needed for a single SCR at an individual plant and 36 months at a single plant with multiple boilers. EPA's assessment of units with SCR retrofit potential indicate the majority fall into this first classification, *i.e.,* a single SCR at a power plant. Given that some of the assumed SCR retrofit potential occurs at plants with multiple units identified with retrofit potential, and given the total volume of SCR retrofit capacity being implemented across the region, The EPA is proposing 36 months as an appropriate time frame to accommodate both instances as well as scheduling necessities attributable to the regional-scale nature of the program.

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[151] *See* EGU NO_X Mitigation Strategies Proposed Rule TSD for additional discussion.

[152] A month-by-month evaluation of SNCR installation is discussed in EPA's NO_X Mitigation Strategies Proposed Rule TSD and in EPA's "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies". The analysis in this exhibit estimates the installation period from contract award as within a 10–13-month timeframe. The exhibit also indicates a 16-month timeframe from start to finish, inclusive of pre-contract award steps of the engineering assessment of technologies and bid request development. The timeframe cited for installation of SNCR at an individual source in this action is consistent with this more complete timeframe estimated by the analysis in the exhibit.

[153] IPM Model-Updates to Cost and Performance for APC Technologies. SCR Cost Development Methodology for Coal-fired Boilers. February 2022.

Further, the EPA notes that it has previously determined in the context of ozone transport that regional scale implementation of SCRs at numerous EGUs is achievable in 36 months. *See* 63 FR 57356, 57447–50 (October. 27, 1998). The EPA has at times also found up to 39–48 months to be an appropriate installation timeframe for regionwide actions when the EPA is evaluating multiple installations at multiple locations.[154] However, as discussed in greater detail in Section VII.A in this proposed rule, the EPA now recognizes that the *Wisconsin* decision invalidated the standard under which the EPA had been evaluating appropriate compliance timeframes for purposes of assessing interstate transport under the good neighbor provision when the Agency had concluded a 39–48 month timeframe to install SCR was appropriate.

The Agency examined the cost for retrofitting a coal unit with new SCR technology, which typically attains controlled NO_X rates of 0.05 lbs/mmBtu or less. These updates are further discussed in the EGU NO_X Mitigation Strategies Proposed Rule TSD.[155] Based on the characteristics of coal units of 100 MW or greater capacity that do not have post-combustion NO_X control technology, the EPA estimated a weighted-average representative SCR cost of $11,000 per ton.[156]

The 0.05 lb/mmBtu emission rate performance assumption for new SCR retrofits is supported by historical data and third party independent review by pollution control engineering and consulting firms. The EPA first examined unit-level emission rate data for coal-fired units that had a relatively recent SCR installation (within the last 10 years). These SCR retrofits reflect the most recent vintage of the pollution control technology applied to the power sector and are representative of new SCR retrofit capability. Although regulatory requirements or economic incentives were not necessarily in place during this time period for these SCRs to operate at their full potential, the EPA found that half of these units had still demonstrated a seasonal emission rate of 0.05 lb/mmBtu or lower and 78 percent had demonstrated this rate on a monthly basis. The best performing 10 percent of these SCRs were demonstrating seasonal emission rates of 0.036 lb/mmBtu during this time.

While the EPA identified the 0.05 lb/mmBtu performance assumption consistent with historical data, these performance levels are also informed and consistent with the Agency's IPM modeling assumptions used for more than a decade. These modeling assumptions are based on input from leading engineering and pollution control consulting entities. Most recently, these data assumptions were affirmed and updated in the summer of 2021 and included in the docket for this rulemaking. The EPA relies on a global firm providing engineering, construction management, and consulting services for power and energy with expertise in grid modernization, renewable energy, energy storage, nuclear power, and fossil fuels. Their familiarity with state-of-the art pollution controls at power plants derives from experience providing comprehensive project services—from consulting, design, and implementation to construction management, commissioning, and operations/maintenance. This review and update supported the 0.05 lb/mmBtu performance assumption as a representative emission rate for new SCR across coal types.

The EPA performed an assessment for oil/gas steam units in which it evaluated the nationwide performance of those units with SCR technology. For these units, the EPA tabulated EGU NO_X ozone season emissions data from 2009 through 2021 and calculated an average NO_X ozone season emissions rate across the fleet of oil- and gas-fired EGUs with SCR for each of these years. The EPA identified the third lowest year which yielded an SCR performance rate of 0.03 lb/mmBtu as representative of performance for this retrofit technology applied to this type of EGU. Next, the EPA evaluated the emissions and operational characteristics for the existing oil/gas steam fleet lacking SCR technology. EPA's analysis indicated that the majority of reduction potential (approximately 76 percent) from these units occurred at units greater than or equal to 100 MW and that were emitting more than 150 tons per ozone season (*i.e.,* approximately 1 ton per day). Moreover, the cost of reductions for units falling below these criteria increased significantly. Therefore, the EPA identified the portion of the oil/gas steam fleet meeting this criteria as representative of the SCR retrofit reduction potential.[157] For this segment of the oil/gas steam units lacking post-combustion NO_X control technology, the EPA estimated a weighted-average representative SCR cost of $7,700 per ton.

f. Generation Shifting

Finally, EPA evaluates emissions reduction potential from generation shifting across the representative dollar per ton levels estimated for the emissions controls considered above. As the cost of emitting NO_X increases, it becomes increasingly cost-effective for units with lower NO_X rates to increase generation, while units with higher NO_X rates reduce generation. Because the cost of generation is unit-specific, this generation shifting occurs incrementally on a continuum. Consequently, there is more generation shifting at higher cost NO_X-control levels.

It is reasonable for the EPA to quantify and include the emissions reduction potential from generation shifting at cost levels that are representative of the emissions control technologies evaluated in the multi-factor analysis, because all EGUs that would be regulated by this proposed rule participate in highly coordinated, interconnected systems where generation shifting will inevitably occur in response to pollution control requirements. If the EPA did not account for such emissions reduction potential in its analysis at Step 3, seeking emissions reductions from pollution control measures at higher-NO_X-emitting EGUs would still incentivize generation shifting toward lower-NO_X-emitting EGUs when sources comply under the remedy mechanism established in Step 4, and the corresponding reductions in emissions achieved through such generation shifting would potentially substitute for some of the emissions reductions intended through control operation and installation, potentially lessening the implementation of those mitigation strategies. Generation shifting treatment and results are discussed in greater detail in the EGU NO_X Mitigation Strategies Proposed TSD and the Ozone Transport Policy Analysis Proposed Rule TSD.

[154] *See, e.g.,* CSAPR Close-Out, 83 FR 65878, 65895 (December 21, 2018). *See also* Final Report: Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA–600/R–02/073 (Oct. 2002), available at *https://nepis.epa.gov/Adobe/PDF/P1001G0O.pdf.*

[155] As noted in that TSD, approximately half of the recent SCR retrofits (*i.e.,* installed in the last 10 years) have demonstrated an emission rate across the ozone season below 0.05 lb/mmBtu, even absent a requirement or strong incentive to operate at that level in many cases.

[156] This cost estimate is representative of coal units lacking any post-combustion control. A subset of units within the universe of coal sources with SCR retrofit potential, but that have an existing SNCR technology in place would have a weighted average cost that falls above this level, but still cost effective. See the EGU NO_X Mitigation Strategies Proposed Rule TSD for more discussion.

[157] The EPA used a 3 year average of 2019–2021 reported ozone season emissions to derive a tons per ozone season value representative for each covered oil/gas steam unit.

The EPA notes that its treatment of generation shifting here is consistent with the prior CSAPR rulemakings and is grounded on the same statutory authority. *See, e.g.,* 76 FR 48208, 48280 (August 8, 2011). As the EPA explained in the CSAPR Update: [158]

> The good neighbor provision requires state and federal plans implementing its requirements to ''prohibit[ ] . . . *any source or other type of emissions activity within the State* from emitting any air pollutant in *amounts* which will'' significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any other state. CAA section 110(a)(2)(D)(i)(I) (emphasis added). . . . [T]he statute does not limit the EPA's authority under the good neighbor provision to basing regulation only to control strategies for individual sources. The statute authorizes the state or EPA in promulgating a plan to prohibit emissions from ''any source or other type of emissions activity within the State'' that contributes (as determined by EPA) to the interstate transport problem with respect to a particular NAAQS. This broad statutory language shows that Congress was directing the states and the EPA to address a wide range of entities and activities that may be responsible for downwind emissions. However, this provision is silent as to the type of emissions reduction measures that the states and the EPA may consider in establishing emissions reduction requirements, and it does not limit those measures to individual source controls. . . . The EPA reasonably interprets this provision to authorize consideration of a wide range of measures to reduce emissions from sources, which is consistent with the broad scope of this provision, as noted immediately above.

81 FR 74545.[159] The EPA continued to apply this same understanding in the Revised CSAPR Update. *See* 86 FR 23054, 23095–97 (April 30, 2021); *see also* 85 FR 68964, 68992–93 (October 30, 2020).

The EPA requests comment on the suite of mitigation technologies for EGUs described earlier and assessed in the determination of significant contribution. The EPA requests comment on the assumed performance or emissions rate of the technology, the representative cost, and the timing for installation.[160] Additionally, the EPA requests comment on whether other EGU ozone-season NO_X Mitigation technologies should be required to eliminate significant contribution. For instance, the EGU NO_X Mitigation Strategies Proposed Rule TSD discusses certain mitigation technologies that have been applied to ''peaking'' units (small, low capacity factor gas combustion turbines often only operating during periods of peak demand). To the extent that any of these sources meet the applicability requirements and are covered in the Group 3 trading program under this proposed rulemaking, they would have an incentive to reduce emissions consistent with the ozone season NO_X allowance price. The EPA has not identified determinative evidence that there are additional meaningful, cost-effective upwind reductions from these emission controls that are not already being addressed by state rules. EPA's analysis discussed in the EGU NO_X Mitigation Strategies Proposed Rule TSD highlights that there are 32 units emitting more than 10 tons per year on average for the 2019–2021 ozone seasons and lacking combustion controls or more advanced controls (totaling approximately 1,000 tons of ozone season NO_X emissions in 2021). Some of the units in the limited inventory are subject to state requirements delivering additional reductions by 2023. Moreover, the EPA analysis suggested $25,000–$30,000 per ton estimates for dry low NO_X burners or ultra-low NO_X burners at these units, and over $100,000 per ton for SCR retrofit at some combustion turbines. Therefore, the EPA is not proposing any additional reductions from new controls for inclusion in its combustion control or retrofit technology breakpoints. Although the EPA is not proposing a mitigation technology for this type of unit, it requests comment on the potential emissions reductions and cost from such sources in covered states that do not currently have mitigation requirements for such sources.

2. Non-EGU NO_X Mitigation Strategies

a. Determining Non-EGU NO_X Reduction Potential

The number of different industries and emissions unit categories and types, as well as the total number of emissions units that comprise the universe of non-EGU sources, makes it challenging to define a single method to identify appropriate control technologies, measures, or strategies and resulting impactful emissions reductions. Because of these challenges, the EPA adopted a different approach for assessing non-EGU NO_X emissions reduction potential than the approach for EGUs described in the preceding section. To assess emissions reduction potential from non-EGUs, the EPA first performed a screening assessment to identify those industries that could have the greatest air quality impact at downwind receptors. This was followed by an assessment estimating annual NO_X emissions reduction potential at specific cost thresholds for each of the most impactful industries. Next, the EPA estimated the reductions in ozone concentrations resulting from the emissions reductions for each industry in each of the 27 linked upwind states. As described later, the results indicate that the most impactful industries fall into two tiers based on the estimated reductions in ozone concentrations associated with the NO_X emissions reductions.

The Agency incorporated air quality information as a first step in an analytical framework to help determine potentially impactful industries to focus on for further assessing potential controls, emissions reduction potential, air quality improvements, and costs. The EPA developed the analytical framework using inputs from the air quality modeling for the Revised CSAPR Update for 2023,[161] as well as the projected 2023 annual emissions inventory from the 2016v2 emissions platform that was used for the air quality modeling for this proposed rule. Additional information on the analytical framework is presented in the Non-EGU Screening Assessment memorandum available in the docket.

Using the Revised CSAPR Update modeling for 2023, the EPA identified upwind states linked to downwind nonattainment or maintenance receptors using the 1 percent of the NAAQS threshold criterion, which is 0.7 ppb (1 percent of a 70 ppb NAAQS). In 2023 there were 27 linked states for the 2015 ozone NAAQS: Alabama, Arkansas, California, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming.

[158] The EPA discussed its legal authority for and the technical viability of generation shifting as a method of emissions reduction under the good neighbor provision in the CSAPR Update. *See especially* 81 FR 74504, 74545–47; *see also* CSAPR Update Response to Comment Document at 546–550 (legal authority); *id.* 528–533 (technical feasibility). *See* Final Revised CSAPR Update, 86 FR 23096–97.

[159] The EPA also noted in the CSAPR Update, ''Interpreting the Good Neighbor Provision to be sufficiently broad to authorize reliance on generation shifting is also consistent with the legislative history for the 1970 CAA Amendments. The Senate Report stated that to achieve the NAAQS, '[g]reater use of natural gas for electric power generation may be required,' S. Rep. No. 91–1196 at 2.'' 81 FR 74545 n.141.

[160] The feasibility of the timetable for emissions reductions from both EGUs and non-EGUs is further addressed in Section VII.A of this proposed rule.

[161] The EPA used the Revised CSAPR Update air quality modeling for this screening assessment because the air quality modeling for this proposed rule was not completed in time to support the assessment.

To analyze non-EGU emissions units, the EPA aggregated the underlying projected 2023 emissions inventory data into industries defined by 4-digit NAICS. Then for linked states, the EPA followed the 2-step process below:

Step 1—The EPA identified industries whose potentially controllable emissions have the greatest ppb impact on downwind air quality, and

Step 2—The EPA determined which of the most impactful industries and emissions units had the most emissions reductions that would make meaningful air quality improvements at the downwind receptors at a marginal cost threshold the EPA determined using underlying control device efficiency and cost information.

To estimate the contributions by industry, defined by 4-digit NAICS, at each downwind receptor the EPA used the 2023 state-receptor specific Revised CSAPR Update ppb/ton values and the Revised CSAPR Update calibration factors used in the air quality assessment tool (AQAT) for control analyses in 2023.[162] The EPA focused on assessing emissions units that emit greater than 100 tons per year (tpy) of NO_X.[163] By limiting the focus to potentially controllable emissions, well-controlled sources that still emit greater than 100 tpy are excluded. Instead, the focus is on uncontrolled sources or sources that could be better controlled at a reasonable cost. As a result, reductions from any industry identified by this process are more likely to be achievable and to lead to air quality improvements.

From this information, the EPA prepared a summary with the estimated total, maximum, and average contributions from each industry and the number of receptors with contributions greater than or equal to 0.01 ppb from each industry.[164] The EPA used this information to identify breakpoints in the data to determine which industries to focus on for the next steps in its analysis, as described in the Non-EGU Screening Assessment memorandum.

A review of the maximum contribution data indicated that the EPA should focus the assessment of NO_X reduction potential and cost primarily on four industries. These industries each (1) have a maximum contribution to any one receptor of greater than 0.10 ppb and (2) contribute greater than or equal to 0.01 ppb to at least 10 receptors. The four industries identified below comprise the ''Tier 1'' non-EGU industries.

- Pipeline Transportation of Natural Gas
- Cement and Concrete Product Manufacturing
- Iron and Steel Mills and Ferroalloy Manufacturing
- Glass and Glass Product Manufacturing

In addition to these industries, the maximum contribution data suggests including five additional industries as a second tier in the assessment. These industries each either have (1) a maximum contribution to any one receptor greater than or equal to 0.10 ppb but contribute greater than or equal to 0.01 ppb to fewer than 10 receptors, or (2) a maximum contribution less than 0.10 ppb but contribute greater than or equal to 0.01 ppb to at least 10 receptors. The five industries identified below comprise the ''Tier 2'' non-EGU industries.

- Basic Chemical Manufacturing
- Petroleum and Coal Products Manufacturing
- Metal Ore Mining
- Lime and Gypsum Product Manufacturing
- Pulp, Paper, and Paperboard Mills

For additional discussion of the contribution information, see Appendix A of the Non-EGU Screening Assessment memorandum included in the docket for this proposed rulemaking.

Next, to identify an annual cost threshold for evaluating potential emissions reductions in the Tier 1 and Tier 2 industries, the EPA used the Control Strategy Tool (CoST),[165] the Control Measures Database (CMDB),[166] and the projected 2023 emissions inventory to prepare a listing of potential control measures, and costs, applied to non-EGU emissions units in the projected 2023 emissions inventory. Using these data, the EPA plotted curves for Tier 1 industries, Tier 2 industries, Tier 1 and 2 industries, and all industries at $500 per ton increments. Figure 1 on page 4 of the Non-EGU Screening Assessment memorandum, which is available in the docket for this proposed rulemaking, indicates there is a ''knee in the curve'' at approximately $7,500 per ton (all non-EGU cost estimates in the assessment and presented in the rest of this section are in 2016 dollars). The EPA used this marginal cost threshold to further assess potential control strategies, estimated emissions reductions, air quality improvements, and costs from the potentially impactful industries. Note that controls and related emissions reductions are available at several estimated cost levels up to the $7,500 per ton threshold. (These costs do not include monitoring, recordkeeping, reporting, or testing costs.)

Next, using the marginal cost threshold of $7,500 per ton, to estimate emissions reductions and costs the EPA processed the CoST run using the maximum emissions reduction algorithm,[167] with known controls.[168] The EPA identified controls for non-EGU emissions units in the Tier 1 and Tier 2 industries that cost up to $7,500 per ton. The EPA then calculated air quality impacts associated with the estimated reductions for the 27 linked states in 2023 using the following steps.

1. The EPA binned the estimated reductions by 4-digit NAICS code into the Tier 1 and Tier 2 industries.

2. The EPA used the 2023 state-receptor specific Revised CSAPR Update ppb/ton values and the Revised CSAPR Update calibration factors used in the AQAT for control analyses in 2023. The EPA multiplied the estimated

[162] The calibration factors are receptor-specific factors. For the Revised CSAPR Update, the calibration factors were generated using 2016 base case and 2023 base case air quality model runs. These receptor-level ppb/ton factors are discussed in the Ozone Transport Policy Analysis Final Rule TSD found here: *https://www.epa.gov/sites/default/files/2021-03/documents/ozone_transport_policy_analysis_final_rule_tsd_0.pdf.*

[163] In the non-EGU emissions reduction assessment prepared for the Revised Cross State Air Pollution Rule Update (*https://www.regulations.gov/document/EPA-HQ-OAR-2020-0272-0014*), The EPA reviewed emissions units with >150 tpy of NO_X emissions. In this assessment, EPA broadened the scope to include emissions units with greater than or equal to 100 tpy of NO_X emissions.

[164] The EPA chose to include in the Non-EGU NO_X reduction potential analysis those industries that contribute at least 0.01 ppb to a downwind receptor in order to focus the analysis on the most impactful industries. The 0.01 criterion is based on an analysis of the distribution and relative magnitude of contributions from 41 industries, as identified in the Non-EGU Screening Assessment memorandum. From this analysis the EPA determined that 0.01 ppb provides a meaningful conservative breakpoint for screening out non-impactful industries from the Non-EGU analysis in this proposed rule. Details on this analysis that provides the basis for using 0.01 ppb can be found in the Non-EGU Screening Assessment memorandum.

[165] Further information on CoST can be found at the following link: *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.*

[166] The CMDB is available at the following link: *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.*

[167] The maximum emissions reduction algorithm assigns to each source the single measure (if a measure is available for the source) that provides the maximum reduction to the target pollutant. For more information, *see* the CoST User's Guide available at the following link: h*ttps://www.cmascenter.org/cost/documentation/3.7/CoST%20User's%20Guide/.*

[168] Known controls are well-demonstrated control devices and methods that are currently used in practice in many industries. Known controls do not include cutting edge or emerging pollution control technologies.

non-EGU reductions by the ppb/ton values and by the receptor-specific calibration factor to estimate the ppb impacts from these emissions reductions.

Next, because boilers represent the majority emissions units in the Tier 2 industries for which there were controls that cost up to $7,500 per ton, the EPA further targeted emissions reductions and air quality improvements in Tier 2 industries by identifying potentially impactful industrial, commercial, and institutional (ICI) boilers. To identify potentially impactful boilers, using the projected 2023 emissions inventory in the linked upwind states, the EPA identified a universe of boilers with greater than 100 tpy NO_X emissions that had contributions at downwind receptors.[169] [170] The EPA refined the universe of boilers to a subset of impactful boilers by sequentially applying the three criteria below to each boiler. This approach is similar to the overall analytical framework and was tailored for application to individual boilers.[171]

- Criterion 1—Estimated maximum air quality contribution at an individual receptor of greater than or equal to 0.0025 ppb or estimated total contribution across downwind receptors of greater than or equal to 0.01 ppb.
- Criterion 2—Controls that cost up to $7,500 per ton.
- Criterion 3—Estimated maximum air quality improvement at an individual receptor of greater than or equal to 0.001 ppb.

Lastly, the EPA updated its analytical framework to the 2026 analytic year by which the EPA is proposing non-EGU controls be installed across the Tier 1 and Tier 2 industries and various emissions unit types. The EPA concluded, based on the most recent information available from the CSAPR Update Non-EGU TSD,[172] that controls on all of the non-EGU emissions units cannot be installed by the 2023 ozone season. The EPA prepared the non-EGU screening assessment for the year 2026 by generally applying the analytical framework detailed above, with some modifications. The updated screening assessment results for 2026 are discussed in Section VI.C.2 [173] of this proposed rule. Specifically, the EPA

- Retained the impactful industries identified in Tier 1 and Tier 2, the $7,500 cost per ton threshold, and the methodology for identifying impactful boilers;
- Modified the framework to address challenges associated with using the projected 2023 emissions inventory by using the 2019 emissions inventory; [174] and
- Updated the air quality modeling data by using the most recent air quality modeling data for this proposal for the analytic year 2026.

3. Other Stationary Sources NO_X Mitigation Strategies

As part of its analysis for this proposed rule, the EPA also reviewed whether NO_X mitigation strategies for any other stationary sources may be appropriate. In this section, the EPA discusses three classes of units that have historically been excluded from our interstate air transport programs: (1) Units less than or equal to 25 MW, (2) solid waste incineration units, and (3) cogeneration units. EPA's initial assessment does not lead it to propose inclusion of the units less than or equal to 25 MW, but the EPA is requesting comment on any particular units within this category that may offer cost-effective reduction potential. The EPA is also taking comment on and considering whether to include emissions limitations for solid waste incineration units (many of which are less than 25 MW) in a final rule, as discussed later. For cogeneration units previously exempted from EGU emissions budgets established through ozone interstate transport rules, the EPA has not identified a basis for inclusion in this proposal.

The EPA has not historically identified substantial emissions reduction or air quality gains from corresponding reductions from these segments of units and has therefore not considered inclusion of these segments of stationary sources in its federal programs for interstate transport.

However, given the need to implement a full remedy to address interstate transport, the more stringent 2015 ozone NAAQS of 70 ppb, and the extended period of time for which the EPA projects upwind contribution to persistent nonattainment and maintenance problems, the EPA is requesting comment on whether sources within these three segments—units serving a generator equal or smaller than 25 MW, cogeneration units, and solid waste incineration units—could merit inclusion within EPA's proposed NO_X mitigation strategy in this rule. Specifically, the EPA requests comment on available NO_X mitigation technologies, NO_X emissions rate performance, total potentially available NO_X reductions, installation timing, cost, air quality impacts, source-specific information, and any other information that could inform a control determination specific to these three types of units. The EPA provides an assessment of these three segments, their emissions control opportunities, and potential air quality benefits below. Additional considerations are further discussed in the EGU NO_X Mitigation Strategies Proposed Rule TSD.

a. Units Less Than or Equal to 25 MW

The EPA has historically not included control requirements for emissions for units less than or equal to 25 MW for three primary reasons: Low potential reductions, relatively high cost per ton of reduction, and high monitoring and other compliance burdens. In the January 11, 1993, Acid Rain permitting rule, the EPA provided for a conditional exemption from the emissions reduction, emitting, and emissions monitoring requirements of the Acid Rain Program for new units having a nameplate capacity of 25 MWe or less that burn fuels with a sulfur content no greater than 0.05% by weight, because of the *de minimis* nature of their potential SO_2, CO_2 and NO_X emissions. *See* 63 FR 57484. The NO_X SIP Call identified these as *Small Point Sources.* For the purposes of that rulemaking, the EPA considered electricity generating boilers and turbines serving a generator 25 MWe or less, to be small point sources. The EPA noted that the collective emissions from small sources

[169] The EPA used the 2023fj non-EGU point source inventory files from the 2016v2 emissions platform.

[170] Maryland, Missouri, Nevada, and Wyoming did not have boilers with >100 tpy NO_X emissions.

[171] For the impactful boiler assessment, the estimated air quality contributions and improvements were not based on modeling of individual emissions units or emissions source sectors. The air quality estimates were derived by using the 2023 state/receptor specific Revised CSAPR Update ppb/ton values and the Revised CSAPR Update calibration factors used in AQAT. The results indicate a level of precision not supported by the underlying air quality modeling. The results were intended to provide an indication of the relative impact across sources.

[172] Final Technical Support Document (TSD) for the Final Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Assessment of Non-EGU NO_X Emissions Controls, Cost of Controls, and Time for Compliance Final TSD (''CSAPR Update Non-EGU TSD''), August 2016, available at *https://www.epa.gov/csapr/assessment-non-egu-NOx-emission-controls-cost-controls-and-time-compliance-final-tsd.*

[173] The non-EGU screening assessment is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs. For more detailed discussion of these issues, *see* Section VII.C of this proposed rule and the Non-EGU Sectors TSD included in the docket.

[174] The EPA determined that the 2019 inventory was appropriate because it provided a more accurate prediction of potential near-term emissions reductions. *See* the Non-EGU Screening Assessment memorandum, available in the docket, for a discussion of the challenges associated with using the projected 2023 emissions inventory.

were relatively small and the administrative burden to the states and regulated entities of controlling such sources was likely to be considerable. As a result, the rule did not assume reductions from those sources in state emissions budgets requirements (63 FR 57402). Similar size thresholds have been incorporated in subsequent transport programs such as CAIR and CSAPR. As these sources were not identified as having cost-effective reductions and so were not included in those programs, they were also exempted from certain reporting requirements and the data for these sources is, therefore, not of the same caliber as that of covered larger sources.

EPA's preliminary survey of current data, compared to this initial justification, does not appear to offer a compelling reason to depart from this past practice by requiring emission reductions from these small EGU sources as part of this rule. For instance, as explained in the EGU NO_X Mitigation Strategies Proposed Rule TSD, EPA has evaluated the costs of SCR retrofits at small EGUs using its Retrofit Cost Analyzer and found that such controls become markedly less cost-effective at lower levels of generating capacity. This analysis concluded that, after controlling for all other unit characteristics, the dollar per ton cost for a SCR retrofit increases by about a factor of 2.5 when moving from a 500 MW to a 10 MW unit, and a factor of 8 when moving to a 1 MW unit.[175] Moreover, the EPA estimates that under 6% of nationwide EGU emissions come from units less than 25 MW and not covered by current applicability criteria due to this size exemption threshold. Therefore, the EPA is not proposing to require any emissions reductions from these units, but the EPA requests comment on whether there are any cost-effective reductions and corresponding air quality benefits to nonattainment or maintenance receptors from any units within this segment.

b. Municipal Solid Waste Units

The EPA seeks comment on whether NO_X emissions reductions should be sought from municipal solid waste combustor units (MWCs) to address interstate ozone transport. As noted below, MWCs emit substantial amounts of NO_X, and some states have required emissions limits for these facilities that are more stringent than the federal requirements contained within EPA's new source performance standard (NSPS) for this industry. These more stringent limits, if applied broadly to the 26 states included in this proposed FIP action, would create an additional means of reducing NO_X emissions.

MWCs burn garbage and other non-hazardous solid material using a variety of combustion techniques. Section 2.1, Refuse Combustion, of the EPA emissions factor reference document AP–42 [176] contains a description of the seven different combustion process technologies most commonly used in the industry. A copy of Section 2.1 of AP–42 is included within the Docket for this proposed rule. These seven combustion processes are as follows: Mass burn waterwall, mass burn rotary waterwall, mass burn refractory wall, refuse-derived fuel-fired, fluidized bed, modular starved air, and modular excess air. Section 2.1 of AP–42 contains detailed process descriptions of each of these MWC processes. During the combustion process, a number of pollutants are produced, including NO_X, which forms through oxidation of nitrogen in the waste and from fixation of nitrogen in the air used to burn the waste. NO_X emissions from MWCs are typically released through tall stacks which enables the emissions to be transported long distances.

Most MWCs are cogeneration facilities that recover heat from the combustion process to power a turbine to produce electricity. According to a 2018 report from the Energy Recovery Council,[177] 72 of the 75 operating MWC facilities in the U.S. produce electricity from heat captured from the combustion process. The electrical output of MWCs is relatively small compared to the EGUs that will be regulated per the proposed requirements of Section VII.B of this proposal, with most MWCs having an electrical output capacity of less than 25 MW. The Non-EGU Sectors TSD located in the Docket identifies the electrical output capacity for MWC units that produce electricity as reflected in EPA's NEEDS database.

However, despite their relatively small electricity-generating potential, NO_X emissions from MWCs located in the transport states identified in this proposal are substantial. According to the EPA's NEI database, MWCs emitted 19,222 tons of NO_X in 2017 in the ten states included in this proposal that contain them. Table 8 of the Non-EGU Sectors TSD contains a list of MWC facilities located within the states included in this proposal along with their NO_X emissions as reported to the NEI.

The EPA has promulgated NO_X emissions limits for large MWCs, defined as those that process 250 tons of municipal solid waste per day or more at 40 CFR part 60, subpart Cb and 40 CFR part 60, subpart Eb. Subpart Cb is applicable to MWCs that commenced construction on or before September 20, 1994, while Subpart Eb is applicable to MWCs that commenced construction, modification, or reconstruction after September 20, 1994. The NO_X limits for subpart Cb are found within Tables 1 and 2 of 40 CFR 60.39b and range from 165 to 250 ppm depending on the combustor design type. The NO_X limits for Subpart Eb are found at 40 CFR 60.52b(d) and are 180 ppm during a unit's first year of operation and drop to 150 ppm afterwards, applicable across all combustor types. These limits correspond to NO_X emissions rates of 0.31 and 0.26 lbs/MMBtu, respectively.

Section 182(b)(2) and (f) of the CAA requires states with ozone nonattainment areas classified as Moderate or higher to adopt regulations with control requirements representing reasonably available control technology (RACT) for major sources of VOCs and NO_X. Sections 184(b)(1)(B) and 182(f) of the Act require RACT requirements be adopted in all areas included within the Ozone Transport Region (OTR). Due primarily to the NO_X RACT requirement, many states within the Northeast located within the OTR have adopted NO_X emissions limits for MWCs that are more stringent than what would otherwise be required by EPA's NSPS or the emissions guideline for these units. For example, the Montgomery County Resource Recovery Facility in Maryland is required to meet a NO_X RACT limit of 140 ppm (at 7 percent oxygen) on a 24-hour block average. Additionally, MWC facilities located in Virginia operated by Covanta, Inc., are required to meet a NO_X RACT limit of 110 ppm (at 7 percent oxygen) on a 24-hour basis, and a limit of 90 ppm (at 7 percent oxygen) on an annual average basis.[178] The 110 ppm limit equates to a limit of 0.19 lbs/MMBtu.

The Ozone Transport Commission (OTC) issued a report entitled ''Municipal Waste Combustor Workgroup Report'' in June of 2021. The

[175] Preliminary estimate based on representative coal units with starting NO_X rate of 0.2 lb/mmBtu, 10,000 BTU/kwh, and assuming 80 percent reduction.

[176] ''AP–42, Fifth Edition Compilation of Air Pollutant Emissions Factors, Volume 1: Stationary Point and Area Sources'', available at: *https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors.*

[177] ''2018 Directory of Waste to Energy Facilities''; Energy Recovery Council.

[178] The NO_X permit limits for the Montgomery County facility and the Virginia facilities can be found within the OTC's Municipal Waste Combustor Workgroup Report included within the Docket for this proposed rule.

report is included within the docket for this proposal.[179] The report notes that MWCs are a significant source of NO_X emissions in the OTR, releasing approximately 22,000 tons of NO_X from facilities within 9 OTR states in 2018. The report summarizes the results of a literature review of state-of-the-art NO_X controls that have been successfully installed and concludes that significant reductions could be achieved using several different technologies described in the report, primarily via combustion modifications made to MWC units already equipped with SNCR. The MWC workgroup evaluated the emissions reduction potential from two different control levels, one based on a NO_X concentration in the effluent of 105 to 110 ppm, and another based on a limit of 130 ppm. The workgroup's findings were that a control level of 105 parts per million by volume, dry (ppmvd) on a 30-day average basis and a 110 ppmvd on a 24-hour averaging period would reduce NO_X emissions from MWCs by approximately 7,300 tons annually, and that a limit of 130 ppmvd on a 30 day-average could achieve a 4,000 ton reduction. The report notes that 8 MWC units exist that are already subject to permit limits of 110 ppm, 7 in Virginia, and one in Florida. Studies evaluating MWCs similar in design to the large MWCs in the OTR found NO_X reductions could be achieved at costs ranging from $2,900 to $6,600 per ton of NO_X reduced. Based on the findings of this report, the Commissioners of the states within the OTR adopted a resolution to develop a recommendation for emissions reductions from MWCs during their June 15, 2021, annual public meeting.[180]

In light of the above, the EPA requests comment on whether NO_X limits for MWCs located in the states covered by this proposed rule should be included in the final FIP. Specifically, if NO_X controls are included in the final FIP, the EPA requests comment on the following issues:

- What NO_X emissions limit and averaging time should MWCs be required to meet, and in particular should the EPA adopt emissions rates of 105 ppmvd on a 30-day averaging basis and 110 ppmvd on a 24-hour averaging basis?
- What types of NO_X control technology could be used to reduce NO_X emissions at MWCs, and in particular should the EPA adopt the combustion control modifications made to units with previously installed SNCR identified by the MWC workgroup?
- Whether there is information that would call into question the OTC workgroup's estimated cost of controls for reducing NO_X emissions from MWCs of $2,900 to $6,600 per ton, and, assuming that range is accurate, whether there is any justification for not requiring these controls in light of their relative cost-effectiveness and total level of reductions available, which compare favorably with the proposed EGU and non-EGU control strategies?
- If the final FIP includes emissions reduction requirements for MWCs, should any mechanism be available by which a particular MWC source could seek to establish that meeting the required emissions limits is not feasible?
- Is there any evidence that retrofit of MWC emissions controls would take longer to implement than the 2026 ozone season?
- Would it be appropriate to rely on existing testing, monitoring, recordkeeping, and reporting requirements for MWCs under the applicable NSPS or other requirements?

c. Cogeneration Units

Consistent with prior transport rules, fossil fuel-fired boilers and combustion turbines that produce both electricity and useful thermal energy (generally referred to as ''cogeneration units'') and that meet the applicability criteria to be included in the CSAPR NO_X Ozone Season Group 3 Trading Program would be subject to the emissions reduction requirements established in this rulemaking for EGUs. However, those applicability criteria—which the EPA is not proposing to alter in this rulemaking (*see* Section VII.B.3 of this proposed rule)—exempt some cogeneration units from coverage as EGUs under the trading program. The EPA is proposing that fossil fuel-fired boilers and combustion turbines that produce both electricity and useful thermal energy and that do not meet the applicability criteria to be included in the CSAPR NO_X Ozone Season Group 3 Trading Program as EGUs would not be subject to any other emissions reduction requirements under this rulemaking.

Cogeneration systems can offer considerable environmental benefit as they often require less fuel to produce a given energy output. The average efficiency of fossil-fuel fired power plants in the United States is 33 percent. This means that two-thirds of the energy used to produce electricity at most power plants in the United States is wasted in the form of heat discharged to the atmosphere. By recovering wasted heat, combined heat and power (CHP) systems at cogeneration units typically achieve total system efficiencies of 60 to 80% for producing electricity and useful thermal energy. Some systems achieve efficiencies approaching 90%. This increased efficiency allows the same level of energy use to be achieved with fewer criteria-pollutant and greenhouse gas emissions. Additionally, these systems increase the reliability of access to electrical power for the facilities they serve and reduce the need for electricity from regional power plants and their associated transmission and distribution networks.

According to information contained in the EPA's Combined Heat and Power Partnership's document ''Catalog of CHP Technologies'',[181] there are 4,226 CHP installations in the U.S. providing 83,317 MWe of electrical capacity. Over 99% of the installations are powered by 5 equipment types, those being reciprocating engines (52 percent), boilers/steam turbines (17 percent), gas turbines (16 percent), microturbines (8 percent), and fuel cells (4 percent). The majority of the electrical capacity is provided by gas turbine CHP systems (64 percent) and boiler/steam turbine CHP systems (32 percent). The various CHP technologies described above are available in a large range of sizes, from as small as 1 kilowatt reciprocating engine systems to as large as 300 megawatt gas turbine powered systems.

NO_X emissions from fuel cell powered systems are negligible, and NO_X emissions from rich-burn reciprocating engine, gas turbine, and microturbine systems are low, ranging from 0.013 to 0.05 lbs/mmBTU. NO_X emissions from lean-burn reciprocating engine systems and gas-powered steam turbines systems range from 0.1 to 0.2 lbs/mmBTU. The highest NO_X emitting CHP units are solid fuel-fired boiler/steam turbine systems which emit NO_X at rates ranging from 0.2 to 1.2 lbs/mmBTU. A preliminary assessment from EPA's IPM Summer 2021 Reference Case model suggest that cogeneration units exempted from current EPA EGU transport programs due to such classification are projected to account for approximately 5% of nationwide summer NO_X emissions in 2023.[182]

[179] This report is also available at *https://otcair.org/upload/Documents/Reports/20210624%20OTC%20SAS%20MWC%20report%20final.pdf.*

[180] *See* ''Notice of Proposed rules Taken by Ozone Transport Commission At Annual Public Meeting, June 15, 2021'' included in the Docket for this proposed rule.

[181] This document is available at*: https://www.epa.gov/sites/default/files/2015-07/documents/catalog_of_chp_technologies.pdf.*

[182] *https://www.epa.gov/airmarkets/results-using-epas-power-sector-modeling-platform-v6-summer-2021-reference-case.* The EPA notes that cogeneration units not exempted from EGU Air programs are included in the EPA assessment of

Under the proposed rule (consistent with prior CSAPR rulemakings), certain cogeneration units would be exempt from coverage under the CSAPR NO_X Ozone Season Group 3 Trading Program as EGUs. Specifically, the trading program regulations include an exemption for a unit that qualifies as a cogeneration unit throughout the later of 2005 or the first 12 months during which the unit first produces electricity and continues to qualify through each calendar year ending after the later of 2005 or that 12-month period and that meets the limitation on electricity sales to the grid. In order to meet the trading program's definition of ''cogeneration unit'' under the regulations, a unit (*i.e.,* a fossil-fuel-fired boiler or combustion turbine) must be a topping-cycle or bottoming-cycle type that operates as part of a ''cogeneration system.'' A cogeneration system is defined as an integrated group of equipment at a source (including a boiler, or combustion turbine, and a generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy. A topping-cycle unit is a unit where the sequential use of energy results in production of useful power first and then, through use of reject heat from such production, in production of useful thermal energy. A bottoming-cycle unit is a unit where the sequential use of energy results in production of useful thermal energy first, and then, through use of reject heat from such production, in production of useful power. In order to qualify as a cogeneration unit, a unit also must meet certain efficiency and operating standards in 2005 and each year thereafter. The electricity sales limitation under the exemption is applied in the same way whether a unit serves only one generator or serves more than one generator. In both cases, the total amount of electricity produced annually by a unit and sold to the grid cannot exceed the greater of one-third of the unit's potential electric output capacity or 219,000 MWh. This is consistent with the approach taken in the Acid Rain Program (40 CFR 72.7(b)(4)), where the cogeneration-unit exemption originated.

The EPA is requesting comment on the proposal to exempt cogeneration units meeting the above criteria from any emissions reduction requirements under this proposed rulemaking. The EPA also requests comment on the alternative of requiring fossil fuel-fired boilers in the non-EGU industries identified earlier (Section VI.B.2.a of this proposed rule) that serve electricity generators and that qualify for an exemption from inclusion in the CSAPR NO_X Ozone Season Group 3 Trading Program as EGUs to instead meet the same emissions standards, if any, that would apply under this proposed rulemaking to fossil fuel-fired boilers at facilities in the same non-EGU industries that do not serve electricity generators. These proposed emissions standards are set forth in Section VII.C.5 of this proposed rule. Cogeneration units at these facilities are in the non-EGU industries identified in EPA's non-EGU screening assessment for this proposal (although potential emissions reductions from such cogeneration units were not specifically quantified in the assessment). Under this alternative approach, to the extent these industries have otherwise been determined in this proposal to significantly contribute to nonattainment or interfere with maintenance, the EPA would find that cogeneration units in these industries should not be excluded from EPA's overall NO_X mitigation strategy.

EGU reduction potential in Section VI.B.1 of this proposed rule.

4. Mobile Source NO_X Mitigation Strategies

Under a variety of CAA programs, the EPA has established federal emissions and fuel quality standards that reduce emissions from cars, trucks, buses, nonroad engines and equipment, locomotives, marine vessels, and aircraft (*i.e.,* ''mobile sources''). Because states are generally preempted from regulating new vehicles and engines with certain exceptions (*see generally* CAA sections 209, 177), mobile source emissions are primarily controlled through EPA's federal programs. The EPA has been regulating mobile source emissions since it was established as a federal agency in 1970, and all mobile source sectors are currently subject to NO_X emissions standards. The EPA factors these standards and associated emissions reductions into its baseline air quality assessment in good neighbor rulemaking, including in this proposed rule. These data are factored into EPA's analysis at Steps 1 and 2 of the 4-step framework. As a result of this long history, NO_X emissions from onroad and nonroad mobile sources have substantially decreased (73 percent and 57 percent since 2002, for onroad and nonroad, respectively) [183] and are predicted to continue to decrease into the future as newer vehicles and engines that are subject to the most recent, stringent standards replace older vehicles and engines.[184]

For example, in 2014, the EPA promulgated new, more stringent emissions and fuel standards for light-duty passenger cars and trucks.[185] The fuel standards took effect in 2017, and the vehicle standards phase in between 2017 and 2025. Other EPA actions that are continuing to reduce NO_X emissions include the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements (66 FR 5002; January 18, 2001); the Clean Air Nonroad Diesel Rule (69 FR 38957; June 29, 2004); the Locomotive and Marine Rule (73 FR 25098; May 6, 2008); the Marine Spark-Ignition and Small Spark-Ignition Engine Rule (73 FR 59034; October 8, 2008); the New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder Rule (75 FR 22895; April 30, 2010); and the Aircraft and Aircraft Engine Emissions Standards (77 FR 36342; June 18, 2012).

The EPA is currently developing a new regulatory effort to reduce NO_X and other pollution from heavy-duty trucks (known as the Cleaner Trucks Initiative), as described in the January 21, 2020, Advance Notice of Proposed Rulemaking (85 FR 3306). Heavy-duty vehicles are the largest contributor to mobile source emissions of NO_X and will be one of the largest mobile source contributors to ozone in 2025.[186] Reducing heavy-duty vehicle emissions nationally would improve air quality where the trucks are operating as well as downwind. As required by CAA section 202(a)(3)(A) of the Act, the EPA will be proposing NO_X emissions standards that ''reflect the greatest degree of emissions reduction achievable through the application of technology which the Administrator determines will be available for the model year to which such standards apply, giving appropriate consideration to cost, energy, and safety factors associated with the application of such technology.'' Section 202(a)(3)(C) of the Act requires that standards apply for no less than 3 model years and apply no earlier than 4 years after promulgation.

The EPA's existing regulatory program for mobile sources will

[183] US EPA. Our Nation's Air: Status and Trends Through 2019. *https://gispub.epa.gov/air/trendsreport/2020/#home.*

[184] National Emissions Inventory Collaborative (2019). 2016v1 Emissions Modeling Platform. Retrieved from *http://views.cira.colostate.edu/wiki/wiki/10202.*

[185] Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emissions and Fuel Standards, 79 FR 23414 (April 28, 2014).

[186] Zawacki et al., 2018. Mobile source contributions to ambient ozone and particulate matter in 2025. Atmospheric Environment. Vol 188, pg 129–141. Available online: *https://doi.org/10.1016/j.atmosenv.2018.04.057.*

continue to reduce NO_X emissions into the future, and the EPA is currently taking active steps to ensure that these NO_X reductions occur. The CAA prohibits tampering with emissions controls, as well as manufacturing, selling, and installing aftermarket devices intended to defeat those controls. The EPA currently has a National Compliance Initiative called ''Stopping Aftermarket Defeat Devices for Vehicles and Engines,'' which focuses on stopping the manufacture, sale, and installation of hardware and software specifically designed to defeat required emissions controls on onroad and nonroad vehicles and engines.

C. Control Stringencies Represented by Cost Threshold ($ per Ton) and Corresponding Emissions Reductions

1. EGU Emissions Reduction Potential by Cost Threshold

For EGUs, as discussed in Section VI.A of this proposed rule, the multi-factor test considers increasing levels of uniform control stringency in combination with considering total NO_X reduction potential and corresponding air quality improvements. The EPA evaluated EGU NO_X emissions controls that are widely available (described previously in Section VI.B.1 of this proposed rule), that were assessed in previous rules to address ozone transport, and that have been incorporated into state planning requirements to address ozone nonattainment.

The EPA evaluated the EGU sources within the state of California and found there were no covered coal steam sources greater than 100 MW that would have emissions reduction potential according to EPA's assumed EGU SCR retrofit mitigation technologies.[187] The EGUs in the state are sufficiently well-controlled resulting in the lowest fossil-fuel emission rate and highest share of renewable generation among the 26 states examined at Step 3. EPA's Step 3 analysis, including analysis of the emissions reduction factors from EGU sources in the state, therefore resulted in no additional emission reductions required to eliminate significant contribution from any EGU sources in California.

The tables below summarize the emissions reduction potentials (in ozone season tons) from these emissions controls across the affected jurisdictions. Table VI.C.1–1 focuses on near-term emissions controls while Table VI.C.1–2 includes emissions controls with extended implementation timeframes.

TABLE VI.C.1–1—EGU OZONE-SEASON EMISSIONS AND REDUCTION POTENTIAL (tons)—2023

State	Baseline 2023 OS NO_X	Reduction potential (tons) for varying levels of technology inclusion			
		SCR optimization	SCR optimization + combustion control upgrades *	SCR/SNCR optimization + combustion control upgrades	SCR/SNCR optimization + combustion control upgrades + generation shifting
Alabama	6,648	32	156	156	387
Arkansas	8,955	28	28	28	66
Delaware	423	35	35	39	35
Illinois	7,662	70	70	247	120
Indiana	12,351	856	856	865	1,191
Kentucky	13,900	446	1,047	1,047	2,260
Louisiana	9,987	579	579	675	579
Maryland	1,208	0	0	8	13
Michigan	10,737	4	4	19	4
Minnesota	4,207	98	98	139	246
Mississippi	5,097	73	697	697	697
Missouri	20,094	7,345	7,345	7,569	8,013
Nevada	2,346	66	66	66	66
New Jersey	915	105	105	105	116
New York	3,927	64	64	64	164
Ohio	10,295	1,161	1,161	1,161	1,926
Oklahoma	10,463	199	890	890	890
Pennsylvania	12,242	2,878	2,878	2,978	3,287
Tennessee	4,319	110	110	110	85
Texas	40,860	921	921	1,154	2,344
Utah	15,500	7	7	7	519
Virginia	3,415	164	242	296	271
West Virginia	14,686	554	1,099	1,380	1,927
Wisconsin	5,933	7	7	26	-50
Wyoming	10,191	82	677	690	1,648
Total	236,363	15,883	19,143	20,417	26,806

* The EPA shows reduction potential from state-of-the-art LNB upgrade as near-term reduction emissions controls, but explains in Section VI.B and VI.D of this proposed rule that this reduction potential would not be implemented until 2024 for states not included in the Revised CSAPR Update.

[187] The only coal-fired power plant in California is the 63 MW Argus Cogeneration facility in Trona, California.

TABLE VI.C.1–2—EGU OZONE-SEASON EMISSIONS AND REDUCTION POTENTIAL (tons)—2026

State	Baseline 2026 OS NO_X	Reduction potential (tons) for varying levels of technology inclusion				
		SCR optimization	SCR optimization + combustion control upgrades	SCR/SNCR optimization + combustion control upgrades	SCR/SNCR optimization + combustion control upgrades + SCR/SNCR retrofits	SCR/SNCR optimization + combustion control upgrades + SCR/SNCR retrofits + generation shifting
Alabama	6,701	32	156	156	916	916
Arkansas	8,728	28	28	28	4,697	4,805
Delaware	473	35	35	39	39	39
Illinois	7,763	70	70	247	1,298	1,648
Indiana	9,737	720	720	729	1,740	1,946
Kentucky	13,211	446	885	885	5,450	5,638
Louisiana	9,854	579	579	675	6,102	6,102
Maryland	1,208	0	0	8	8	19
Michigan	9,129	4	4	19	2,959	3,015
Minnesota	4,197	98	98	139	1,613	1,661
Mississippi	5,077	73	697	697	3,164	3,163
Missouri	18,610	7,345	7,345	7,569	11,237	11,364
Nevada	2,438	66	66	66	1,227	1,227
New Jersey	915	105	105	105	105	116
New York	3,927	64	64	64	589	689
Ohio	10,295	1,161	1,161	1,161	1,354	1,709
Oklahoma	10,283	199	890	890	5,968	6,008
Pennsylvania	11,738	2,737	2,737	2,837	4,510	4,919
Tennessee	4,064	81	81	81	81	81
Texas	39,186	921	921	1,154	15,817	17,240
Utah	9,679	7	7	7	7,076	7,059
Virginia	3,243	164	242	263	646	676
West Virginia	14,686	554	1,099	1,380	3,660	4,089
Wisconsin	3,628	7	7	26	54	155
Wyoming	10,249	82	677	690	5,669	5,759
Total	219,017	15,577	18,675	19,917	85,978	90,041

2. Non-EGU Emissions Reduction Potential—Cost Threshold Up to $7,500/ton

The EPA used the updated non-EGU screening assessment for 2026 to estimate emissions reduction potential from the Tier 1 and Tier 2 industries and non-EGU emissions units. The EPA used CoST to identify emissions units, emissions reductions, and associated compliance costs to evaluate the effects of potential non-EGU emissions control measures and technologies. CoST is designed to be used for illustrative control strategy analyses (*e.g.,* NAAQS regulatory impact analyses) and not for unit-specific, detailed engineering analyses. These estimates from CoST identify proxies for (1) non-EGU emissions units that have emissions reduction potential, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units. The cost estimates do not include monitoring, recordkeeping, reporting, or testing costs.

To prepare the non-EGU screening assessment for 2026, the EPA applied the analytical framework detailed in Section VI.B.2 of this proposed rule. The assessment includes emissions units from the Tier 1 industries and impactful high-emitting boilers in Tier 2 Industries. Using the latest air quality modeling for 2026, the EPA identified upwind states linked to downwind nonattainment or maintenance receptors using the 1% of the NAAQS threshold criterion, or 0.7 ppb. In 2026 there are 23 linked states for the 2015 ozone NAAQS: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming.

The EPA re-ran CoST with known controls, the CMDB, and the 2019 emissions inventory.[188] The EPA specified CoST to allow replacing an existing control if a replacement control is estimated to be greater than 10% more effective than the existing control. The EPA did not replace an existing control if the 2019 emissions inventory indicated the presence of that control, even if the CMDB reflects a greater control efficiency for that control. Also, the EPA removed six facilities from consideration because they are subject to an existing consent decree, are shut down, or will shut down by 2026. For additional detail on the six facilities removed, see Appendix B in the Non-EGU Screening Assessment memorandum. Table VI.C.2–1 summarizes the estimated reductions, total ppb improvements across all receptors, and annual total and average annual costs (in 2016 dollars) and Table VI.C.2–2 below summarizes the estimated reductions by state.

[188] The EPA determined that the 2019 inventory was appropriate because it provided a more accurate prediction of potential near-term non-EGU emissions reductions.

TABLE VI.C.2–1—ESTIMATED EMISSIONS REDUCTIONS (OZONE SEASON TONS), TOTAL PPB IMPROVEMENTS ACROSS ALL DOWNWIND RECEPTORS, AND COSTS

Tier	Ozone season emissions reductions (East/West)	Total PPB improvement across all downwind receptors	Annual total cost (million 2016$) (average annual cost/ton)	Industries (# of emissions units >100 tpy in identified industries)
Tier 1 Industries with Known Controls that Cost up to $7,500/ton.	41,153 (37,972/3,181)	4.352	$356.6 ($3,610)	Cement and Concrete Product Manufacturing (47) Glass and Glass Product Manufacturing (44) Iron and Steel Mills & Ferroalloy Manufacturing (39) Pipeline Transportation of Natural Gas (307).
Tier 2 Industry Boilers with Known Controls that Cost up to $7,500/ton.	6,033 (5,965/68)	0.809	54.2 (3,744)	Basic Chemical Manufacturing (17) Petroleum and Coal Products Manufacturing (10) Pulp Paper, and Paperboard Mills (25).

TABLE VI.C.2–2—ESTIMATED EMISSIONS REDUCTIONS (OZONE SEASON TONS) BY UPWIND STATE * **

State	2019 OS NO_X emissions	OS NO_X reductions
AR	8,265	1,654
CA	14,579	1,666
IL	16,870	2,452
IN	19,604	3,175
KY	11,934	2,291
LA	35,831	6,769
MD	2,365	45
MI	18,996	2,731
MN	17,591	673
MO	9,109	3,103
MS	12,284	1,761
NJ	2,025	0
NV	2,418	0
NY	6,003	500
OH	19,729	2,790
OK	22,146	3,575
PA	15,861	3,284
TX	47,135	4,440
UT	6,276	757
VA	7,041	1,563
WI	6,571	2,150
WV	9,825	982
WY	10,335	826
Total	322,793	47,187

* In the non-EGU screening assessment, EPA estimated emissions reduction potential from the non-EGU industries and emissions units. The estimated emissions reductions by state in the table above are from the non-EGU screening assessment; for additional results from the non-EGU screening assessment, including estimated reductions by state and by industry, please see the Non-EGU Screening Assessment memorandum available in the docket.

** In the assessment, EPA used CoST to identify emissions units, emissions reductions, and associated compliance costs to evaluate the effects of potential non-EGU emissions control measures and technologies. CoST is designed to be used for illustrative control strategy analyses (*e.g.,* NAAQS regulatory impact analyses) and not for unit-specific, detailed engineering analyses. These estimates from CoST identify proxies for (1) non-EGU emissions units that have emissions reduction potential, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units. The cost estimates do not include monitoring, recordkeeping, reporting, or testing costs.

In this section, EPA provides a summary of the control technologies applied and their average costs across all of the non-EGU emissions units included in the screening assessment. This summary reflects one approach to organizing this information, which the Agency finds reasonable based on the information available for this proposal. As discussed in Section VI.B.2 of this proposed rule, the number of different industries and emissions unit categories and types present a challenge to defining a single method to identify appropriate control technologies, measures or strategies, and related costs across non-EGU emissions units. Because of the number of industries and emissions unit types, the available information does not easily allow grouping estimated emissions reductions by cost per ton threshold for a few control technologies, measures, or strategies. Nonetheless, Table VI.C.2–3 below provides a summary of estimated reductions and average cost per ton values by control technology across all non-EGU emissions units included in the non-EGU screening assessment. The summary reflects fourteen control technologies applied by CoST across all emissions units in the non-EGU screening assessment. The average cost per ton values range from $585 to $6,300 per ton, all of which are below the marginal cost per ton threshold of $7,500 per ton. Note that the average cost per ton values are in 2016 dollars and reflect simple averages and not a percentile or other representative cost values from a distribution of cost estimates.

The Non-EGU Screening Assessment memorandum includes two other summaries of estimated reductions and average cost per ton values by technology across non-EGU emissions units. First, the memorandum includes a summary by control technology as applied across non-EGU emissions units grouped by the Tier 1 industries and impactful boilers in Tier 2 industries, which given this further disaggregation reflects 18 control technologies across the tiers applied by CoST. Second, the memorandum includes a summary by control technology across non-EGU emissions units grouped by the seven individual Tier 1 and 2 industries, which given this disaggregation reflects 26 control technologies across the industries applied by CoST.

TABLE VI.C.2–3—ESTIMATED EMISSIONS REDUCTIONS (OZONE SEASON TONS), ANNUAL TOTAL COST, AND AVERAGE COST PER TON BY CONTROL TECHNOLOGY ACROSS ALL NON-EGU EMISSIONS UNITS

Control technology	Ozone season emissions reductions	Average cost per ton
Adjust Air to Fuel Ratio and Ignition Retard	212	$2,393
Layered Combustion	12,706	5,457
Low NO_X Burner	231	3,773
Low NO_X Burner and Flue Gas Recirculation	200	4,288
Natural Gas Reburn	284	2,703
Non-Selective Catalytic Reduction	147	585
Non-Selective Catalytic Reduction or Layered Combustion	6,359	4,743
Oxygen Enriched Air Staging	52	764
SCR + DLN Combustion	136	6,301
Selective Catalytic Reduction	12,239	2,543
Selective Catalytic Reduction and Steam Injection	929	3,787
Selective Non-Catalytic Reduction	8,076	1,485
Ultra-Low NO_X Burner	1,670	2,890
Ultra-Low NO_X Burner and Selective Catalytic Reduction	3,946	4,114

Refer to the Non-EGU Screening Assessment memorandum for additional 2026 screening assessment results—including by industry and by state, estimated emissions reductions and costs, as well as by industry, emissions source groups, control technologies, number of emissions units, estimated ozone season reductions, and annual total cost.

D. Assessing Cost, EGU and Non-EGU NO_X Reductions, and Air Quality

To determine the emissions that are significantly contributing to nonattainment or interfering with maintenance, the EPA applied the multi-factor test to EGUs and non-EGUs separately, considering for each the relationship of cost, available emissions reductions, and downwind air quality impacts. Specifically, for each sector, the EPA proposes a determination regarding the appropriate level of uniform NO_X control stringency that would collectively eliminate significant contribution to downwind nonattainment and maintenance receptors. The EPA also evaluated whether the proposed rule resulted in possible over-control scenarios by evaluating if an upwind state is linked solely to downwind air quality problems that could have been resolved at a lower cost threshold, or if an upwind state could have reduced its emissions below the 1 percent air quality contribution threshold at a lower cost threshold.

1. EGU Assessment

For EGUs, the EPA examined the emissions reduction potential associated with each EGU emissions control technology (presented in Section VI.C.1 of this proposed rule) and its impact on the air quality at downwind receptors. Specifically, EPA identified and assessed the projected average air quality improvements relative to the base case and whether these improvements are sufficient to shift the status of receptors from projected nonattainment to maintenance or from maintenance to attainment. Combining these air quality factors, costs, and emissions reductions, the EPA identified a control stringency for EGUs that results in substantial air quality improvement from emissions controls that are available in the timeframe for which air quality problems at downwind receptors persist. For all affected jurisdictions, this control stringency reflects, at a minimum, the optimization of existing post-combustion controls and installation of state-of-the-art NO_X combustion controls, which are widely available at a representative marginal cost of $1,800 per ton. EPA's evaluation also shows that the effective emissions rate performance across affected EGUs consistent with realization of these mitigation measures does not over-control upwind states' emissions relative to either the downwind air quality problems to which they are linked at Step 1 or the 1 percent contribution threshold that triggers further evaluation at Step 3 of the 4-step framework for the 2015 ozone NAAQS.

Similarly, the EPA also identified installation of new SCR post-combustion controls at coal steam sources greater than or equal to 100 MW and for a more limited portion of the oil/gas steam fleet that had higher levels of emissions as components of the required control stringency. These SCR retrofits are widely available by the 2026 ozone season at $11,000 and $7,700 per ton respectively. For all but 3 of the affected states (Alabama, Delaware, and Tennessee—which are no longer linked in 2026 at Steps 1 and 2 in EPA's base case air quality modeling), EPA's evaluation also shows that the effective emissions rate performance across EGUs consistent with realization of these mitigation measures does not over-control upwind states' emissions in 2026 relative to either the downwind air quality problems to which they are linked at Step 1 or the 1 percent contribution threshold that triggers further evaluation at Step 3 of the 4-step framework for the 2015 ozone NAAQS (*see* the Ozone Transport Policy Analysis Proposed Rule TSD for details).

To assess downwind air quality impacts for the nonattainment and maintenance receptors identified in Section V.D of this proposed rule, the EPA evaluated the air quality change at that receptor expected from the progressively more stringent upwind EGU control stringencies that were available for that time period in upwind states linked to that receptor. This assessment provides the downwind ozone improvements for consideration and provides air quality data that is used to evaluate potential over-control situations.

To assess the air quality impacts of the various control stringencies at downwind receptors for the purposes of Step 3, the EPA evaluated changes resulting from the emissions reductions associated with the identified emissions controls in each of the upwind states, as well as assumed corresponding reductions of similar stringency in the downwind state containing the receptor to which they are linked. By applying these emissions reductions to the state containing the receptor, the EPA assumes that the downwind state will implement (if it has not already) an emissions control stringency for its sources that is comparable to the upwind control stringency identified here. Consequently, The EPA is accounting for the downwind state's share of a nonattainment or maintenance problem as a part of the over-control evaluation.[189]

For this assessment, the EPA used an ozone air quality assessment tool (ozone AQAT) to estimate downwind changes in ozone concentrations related to upwind changes in emissions levels. The EPA focused its assessment on the years 2023 and 2026 as they pertain to the last years for which ozone season emissions data can be used for purposes of determining attainment for the Moderate (2024) and Serious (2027) attainment dates. For each EGU emissions control technology, the EPA first evaluated the magnitude of the change in ozone concentrations at the nonattainment and maintenance receptors for each relevant year (*i.e.*, 2023 and 2026). Next, the EPA evaluated whether the estimated change in concentration would resolve the receptor's nonattainment or maintenance concern by lowering the average or maximum design values, respectively, below 71 ppb. For a complete set of estimates, see the Ozone Transport Policy Analysis Proposed Rule TSD or the ozone AQAT excel file.

For 2023, the EPA evaluated potential air quality improvements at the downwind receptors outside of California associated with available EGU emissions control technologies in that timeframe. The EPA determined for the purposes of Step 3 that the average air quality improvement at the receptors relative to the engineering analytics base case was 0.11 ppb for emissions reductions commensurate with optimization of existing SCRs/SNCRs and combustion control upgrades. The EPA determined for the purposes of Step 3 that one receptor in Clark County, Nevada switches from maintenance to attainment with these mitigation strategies in place. Table VI.D.1–1 summarizes the results of EPA's Step 3 evaluation of air quality improvements at these receptors using AQAT.

For 2026, the EPA determined that the average air quality improvement at these receptors relative to the engineering analytics base case was 0.43 ppb for emissions reductions commensurate with optimization of existing SCRs/SNCRs, combustion control upgrades, and new post-combustion control (SCR and SNCR) retrofits at eligible units are assumed to be implemented. The EPA determined for the purposes of Step 3 that in 2026, all but one of the receptors are expected to remain nonattainment or maintenance across these control stringencies, with one receptor in Douglas County, Colorado switching from maintenance to attainment with these mitigation strategies in place.[190] Table VI.D.1–2 summarizes the results of EPA's Step 3 evaluation of air quality improvements at the receptors included in the AQAT analysis. For more information about how this assessment was performed and the results of the analysis for each receptor, refer to the Ozone Transport Policy Analysis Proposed Rule TSD and to the Ozone AQAT included in the docket for this rule.

TABLE VI.D.1–1—AIR QUALITY AT THE 29 RECEPTORS IN 2023 FROM EGU EMISSIONS CONTROL TECHNOLOGIES [a b]

Monitor ID No.	State	County	Average DV (ppb)		Max DV (ppb)	
			Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade	Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade
040278011	Arizona	Yuma	70.53	70.53	72.25	72.24
080350004	Colorado	Douglas	72.35	72.28	72.96	72.89
080590006	Colorado	Jefferson	73.23	73.19	73.84	73.80
080590011	Colorado	Jefferson	74.41	74.38	75.13	75.09
090010017	Connecticut	Fairfield	73.11	73.14	73.82	73.85
090013007	Connecticut	Fairfield	74.45	74.44	75.37	75.36
090019003	Connecticut	Fairfield	76.30	76.29	76.51	76.50
090099002	Connecticut	New Haven	72.11	72.07	74.16	74.12
170310001	Illinois	Cook	70.02	70.02	73.90	73.89
170310032	Illinois	Cook	70.14	70.15	72.78	72.79
170310076	Illinois	Cook	69.64	69.65	72.49	72.49
170314201	Illinois	Cook	70.19	70.18	73.75	73.74
170317002	Illinois	Cook	70.42	70.33	73.37	73.29
320030075	Nevada	Clark	70.09	70.06	71.01	70.98
420170012	Pennsylvania	Bucks	71.09	71.03	72.63	72.57
480391004	Texas	Brazoria	71.71	71.29	73.89	73.45
481210034	Texas	Denton	71.20	71.03	73.06	72.89
482010024	Texas	Harris	76.92	76.55	78.48	78.10
482010055	Texas	Harris	72.50	72.14	73.54	73.17
482011034	Texas	Harris	72.07	71.67	73.32	72.91
482011035	Texas	Harris	69.69	69.31	73.32	72.92
490110004	Utah	Davis	73.65	73.59	75.91	75.85

[189] For EGUs, this analysis for the Connecticut receptors shows no EGU reduction potential from the emissions reduction measures identified given that state's already low-emitting fleet; however, EGU reductions were identified in Colorado and these reductions were included in the over-control analysis.

[190] As in prior rules, for the purpose of defining significant contribution at Step 3, the EPA evaluated air quality changes resulting from the application of the emissions reductions in only those states that are linked to each receptor as well as the state containing the receptor. By applying reductions to the state containing the receptor, the EPA ensures that it is accounting for the downwind state's fair share. This method holds each upwind state responsible for its fair share of the downwind problems to which it is linked. Reductions made by other states in order to address air quality problems at other receptors do not increase or decrease this share. The air quality impacts on design values that reflect the emissions reductions in all linked states and the health and climate benefits from this proposal are discussed in Section IX of this proposed rule.

TABLE VI.D.1–1—AIR QUALITY AT THE 29 RECEPTORS IN 2023 FROM EGU EMISSIONS CONTROL TECHNOLOGIES [a b]—Continued

Monitor ID No.	State	County	Average DV (ppb)		Max DV (ppb)	
			Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade	Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade
490353006	Utah	Salt Lake	74.35	74.29	75.99	75.93
490353013	Utah	Salt Lake	75.27	75.21	75.78	75.72
490570002	Utah	Weber	71.35	71.29	73.29	73.23
490571003	Utah	Weber	71.24	71.19	72.16	72.11
550590019	Wisconsin	Kenosha	73.17	73.07	74.09	73.99
550590025	Wisconsin	Kenosha	69.62	69.46	72.69	72.52
551010020	Wisconsin	Racine	71.70	71.61	73.64	73.55
Average AQ Change Relative to Base (ppb)						0.11
Total PPB Change Across All Receptors Relative to Base [c]						3.08

Table Notes:

[a] These results reflect the inclusion of all identified LNB upgrade potential. Some of which will be implemented in 2023 state emissions budgets, and some be implemented in 2024 state emissions budgets (for those states not included in the Revised CSAPR Update).

[b] The EPA notes that the design values reflected in tables VI.D.1–1 and 2 correspond to the engineering analysis EGU emissions inventory that was used in AQAT to determine state-level baseline emissions and reductions at Step 3. These tools are discussed in greater detail in the Ozone Transport Policy Analysis Proposed Rule TSD.

[c] The cumulative ppb change only shows the aggregate change across all problematic receptors (some of which are located within close proximity to one another) in this part of the Step 3 analysis. Section IX of this proposed rule provides a more complete picture of the air quality impacts of the proposed rule.

TABLE VI.D.1–2—AIR QUALITY AT RECEPTORS IN 2026 FROM EGU EMISSIONS CONTROL TECHNOLOGIES

Monitor ID No.	State	County	Average DV (ppb)		Max DV (ppb)	
			Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit	Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit
40278011	Arizona	Yuma	70.11	70.09	71.81	71.79
80350004	Colorado	Douglas	70.94	70.23	71.55	70.83
80590006	Colorado	Jefferson	72.09	71.42	72.69	72.02
80590011	Colorado	Jefferson	72.97	72.32	73.68	73.02
90010017	Connecticut	Fairfield	71.60	71.52	72.30	72.22
90013007	Connecticut	Fairfield	73.09	72.84	73.99	73.74
90019003	Connecticut	Fairfield	74.83	74.63	75.03	74.83
90099002	Connecticut	New Haven	70.77	70.51	72.78	72.51
170310001	Illinois	Cook	69.05	68.96	72.87	72.77
170310032	Illinois	Cook	69.37	69.32	71.98	71.93
170310076	Illinois	Cook	68.75	68.71	71.56	71.52
170314201	Illinois	Cook	69.10	69.02	72.61	72.53
170317002	Illinois	Cook	69.36	69.18	72.27	72.09
480391004	Texas	Brazoria	70.93	69.35	73.09	71.46
482010024	Texas	Harris	76.28	74.77	77.82	76.28
490110004	Utah	Davis	72.20	71.61	74.42	73.81
490353006	Utah	Salt Lake	73.00	72.40	74.61	74.00
490353013	Utah	Salt Lake	74.10	73.45	74.60	73.95
490570002	Utah	Weber	70.30	69.74	72.22	71.64
550590019	Wisconsin	Kenosha	72.01	71.80	72.91	72.70
550590025	Wisconsin	Kenosha	68.46	68.19	71.48	71.19
551010020	Wisconsin	Racine	70.52	70.33	72.42	72.24
Average AQ Change Relative to Base (ppb)						0.43
Total PPB Change Across All Receptors Relative to Base (ppb)						9.42

Figures 1 and 2 to Section VI.D.1, included in Appendix G of the Ozone Transport Policy Analysis Proposed Rule TSD available in the docket for this rulemaking, illustrate the air quality improvement relative to the estimated representative cost associated with the previously identified emissions control technologies. The graphs show improving air quality at the downwind receptors as emissions reductions commensurate with the identified control technologies are assumed to be implemented. Figure 1 to Section VI.D.1 [191] reflects emissions reductions commensurate with optimization of existing SNCRs and SCRs. Figure 2 to Section VI.D.1 [192] reflects emissions reductions commensurate with installation of new post combustion controls (mainly SCRs) layered on top of the emissions reduction potential from the technologies represented in Figure 1 to Section VI.D.1.[193] The graphic, and underlying AQAT receptor-by-receptor analysis demonstrates that air quality continues to improve at downwind receptors as EPA examines increasingly stringent EGU NO_X control

[191] Included in Appendix G of the Ozone Transport Policy Analysis Proposed Rule TSD, which is available in the docket for this rulemaking.

[192] Included in Appendix G of the Ozone Transport Policy Analysis Proposed Rule TSD, which is available in the docket for this rulemaking.

[193] Included in Appendix G of the Ozone Transport Policy Analysis Proposed Rule TSD, which is available in the docket for this rulemaking.

technologies. While all major technology breakpoints identified in Sections VI.B and VI.C of this proposed rule show continued air quality improvements at problematic receptors and at cost and technology choice levels that are commensurate with mitigation strategies that are proven to be widely available and implemented, EPA's quantification and application of those breakpoints reflect certain exclusions to: (1) Preserve this consistency with widely observed mitigation measures in states, and (2) remove any retrofit assumptions at marginal units that would have much higher dollar per ton representative cost and little or no air quality benefit. For instance, the EPA does not define the SCR retrofit breakpoint ($11,000 per ton) to include retrofit application at steam units less than 100 MW or at oil/gas steam units emitting at less than 150 tons per ozone season. The emissions reductions from these potential categories of measures are small and do not constitute additional ''breakpoints'' in EPA's estimation. They would entail much higher dollar per ton costs, going beyond what is widely observed in the fleet. This careful calibration of technology breakpoints through exclusion of measures that are clearly not cost-effective in terms of air quality benefit allows for the identification of an EGU strategy that is an appropriate reflection of those readily available and widely implemented emissions reduction strategies that will have meaningful downwind air quality impact.

Moreover, these technologies (and representative cost) are demonstrated ozone pollution mitigation strategies that are widely practiced across the EGU fleet and are of comparable stringency to emissions reduction measures that many downwind states have already instituted. The coal SCR retrofit measures driving the majority of the emissions reductions in this action not only reflect industry best practice, but they also reflect prevailing practice among EGUs. More than 60% of the existing coal capacity already has this technology in place. For nearly 25 years, all new coal-fired EGUs that commenced construction have had SCR (or equivalent emissions rates). The 1997 proposed amendments to subpart Da revised the NO_X standard based on the use of SCR. The NO_X SIP Call (promulgated in 1998) established emissions reduction requirements premised on extensive SCR installation (142 units) and incentivized well over 40 GWs of SCR retrofit in the ensuing years.[194] Similarly, the Clean Air Interstate Rule established emissions reductions requirements in 2006 that assumed another 58 units (15 GW) would be installed in the ensuing years among just 10 states, and an even greater volume of capacity chose SCR retrofit measures in the wake of finalizing that action.[195]

Basing emission reduction requirements for EGUs on SCR retrofits is also consistent with regulatory approaches adopted by states, which—particularly in downwind areas more impacted by ozone transport contribution from upwind state emissions—have already adopted SCR-based standards as part of stringent NO_X control programs. Regulatory programs that impose stringent Reasonably Available Control Technology (RACT) requirements on all major power plants and Lowest Achievable Emission Rate (LAER) standards on all new major sources of NO_X have resulted in remaining coal sources in states along the Northeast Corridor such as Connecticut, Delaware, New Jersey, New York, and Massachusetts all being retrofitted with SCR.[196] The Maryland Code of Regulations requires coal fired sources to operate existing SCR controls or install SCR controls by specified dates.[197] Programs like North Carolina's Clean Smokestacks Act and Colorado's Clean Air, Clean Jobs Act have also required or prompted SCR retrofits on units.[198] Unit-level Best Available Retrofit Technology (BART) requirements for the first Regional Haze planning period also determined SCR retrofits (and corresponding emissions rates) were cost-effective controls for a variety of sources in the U.S.[199]

As shown in Figure 1 to Section VI.D.1,[200] the majority of EGU emissions reduction potential and associated air quality improvements estimated for 2023 occurs from optimization of existing SCRs, with some additional reductions from installation of state-of-the-art combustion controls at the same representative cost threshold. At the slightly higher representative cost threshold of $1,800 per ton, there is some additional air quality improvement from optimization of existing SNCRs. These measures taken together represent the control stringency at which near-term incremental EGU NO_X reduction potential and corresponding downwind ozone air quality improvements are maximized. This evaluation shows that EGU NO_X reductions for each of the near-term emissions control technologies are available at reasonable cost and that these reductions provide meaningful improvements in downwind ozone concentrations at the identified nonattainment and maintenance receptors. Figure 1 to Section VI.D.1 [201] highlights (1) the continuous connection between identified emission reduction potential and downwind air quality improvement across the range of near-term mitigation measures assessed, and (2) the cost-effective availability of these reductions and corresponding air quality improvements.

Additional considerations that are unique to EGUs provide additional support for EPA's proposal to include SCR and SNCR optimization as part of the identified near-term control stringency, including:

- These controls are already installed and available for operation on these units;
- they are on average already partially operating, but not necessarily optimized;
- the reductions are available in the near-term (during ozone seasons when the problematic receptors are projected to persist), including by the 2023 ozone season aligned with the Moderate area attainment date; and
- these sources are already covered under the existing CSAPR NO_X Ozone Season Group 2 or Group 3 Trading Programs or the Acid Rain Program and thus have the monitoring, reporting, recordkeeping, and all other necessary elements of compliance with the trading program already in place.

The majority of emissions reduction potential and associated air quality improvements estimated for 2026 occur from retrofitting uncontrolled steam sources with post-combustion controls. At the representative cost threshold of $11,000 per ton, there are significant additional air quality improvements from emissions reductions commensurate with installation of new SCRs and SNCRs. These measures taken together with the near-term emissions reduction measures described

[194] 63 FR 57448.

[195] 71 FR 25345.

[196] EPA–HQ–OAR–2020–0272. Comment letter from Attorneys General of NY, NJ, CT, DE, MA.

[197] COMAR 26.11.38 (control of NO_X Emissions from Coal-Fired Electric Generating Units).

[198] *https://www.epa.gov/system/files/documents/2021-09/table-3-30-state-power-sector-regulations-included-in-epa-platform-v6-summer-2021-refe.pdf.*

[199] *See* table 3–35 BART regulations in EPA IPM documentation available at *https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case.*

[200] Included in Appendix G of the Ozone Transport Policy Analysis Proposed Rule TSD, which is available in the docket for this rulemaking.

[201] Included in Appendix G of the Ozone Transport Policy Analysis Proposed Rule TSD, which is available in the docket for this rulemaking.

previously represent the level of control stringency in 2026 at which incremental EGU NO_X reduction potential and corresponding downwind ozone air quality improvements are maximized. This evaluation shows that EGU NO_X reductions for each of the emissions control technologies are available at reasonable cost and that these reductions can provide improvements in downwind ozone concentrations at the identified nonattainment and maintenance receptors.

The EPA finds that the control stringency that reflects optimization of existing SCRs and SNCRs, installation of state-of-the-art combustion controls, and the retrofitting of new post combustion controls at the coal and oil/gas steam capacity described previously results in nearly 90,000 tons of NO_X reduction (approximately 43 percent of the 2026 baseline level) for the 22 linked states in 2026 subject to a FIP for EGUs, which will deliver notable air quality improvements across all transport-impacted receptors and assist in fully resolving one downwind air quality problem for the 2015 ozone NAAQS. Figure 2 to Section VI.D.1 [202] demonstrates the continuous connection between identified emissions reduction potential and downwind air quality improvement across the range of mitigation measures assessed in 2026. At no point do the additional emission mitigation measures examined here fail to produce corresponding downwind air quality improvements.

The EPA is proposing that emissions reductions commensurate with the full operation of all existing post-combustion controls (both SCRs and SNCRs) and state-of-the-art combustion control upgrades constitute the Agency's selected control stringency for EGUs for those states linked to downwind nonattainment or maintenance in 2023. For those states also linked in 2026, the EPA is determining that the appropriate EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal steam units of 100 MW or greater capacity (excepting circulating fluidized bed units), new SNCR on coal steam units of less than 100 MW capacity and circulating fluidized bed units, and SCR on oil/gas steam units greater than 100 MW that have historically emitted at least 150 tons of NO_X per ozone season.

As noted previously in Section VI.B of this proposed rule and in the EGU NO_X Mitigation Strategies Proposed Rule TSD, the EPA considered other methods of identifying mitigation measures (*e.g.,* SCRs on smaller units, combustion control upgrades on combustion turbines, SCRs on combustion turbines). The emission reductions from these potential categories of measures do not constitute additional ''technology breakpoints'' in EPA's estimation, but rather reflect a different tier of assessment where further mitigation measures are based on inclusion of smaller and/or different generator type of unit (rather than pollution control technology). Emissions reductions from these measures are relatively small and would entail much higher dollar per ton costs, going beyond what is widely observed in the fleet. Although these additional measures are not included in EPA's technology breakpoint analysis discussed above, the EPA did examine the cost, potential reductions, and air quality impact of these additional measures in a supplemental analysis to affirm that they do not merit inclusion in the proposed stringency for this action. Similar to prior rules, there is a notable ''knee-in-the-curve'' breakpoint if these additional measures are included in EPA's analysis. In other words, there are very little additional emissions reductions and air quality improvement at problematic receptors, and the cost associated with these measures increases substantially on a dollar per ton basis. The graphic below illustrates the significant loss in cost-effectiveness of reductions if these measures had been included in EPA's proposed stringency.[203]

This proposed determination regarding the appropriate level of control stringency for EGUs to eliminate significant contribution from upwind states finds that the amounts of NO_X emissions reduction achieved through these strategies at EGUs are necessary and cost-justified under the Step 3 multifactor analysis for as long as the strategies remain available to the sources. In other words, the EPA finds at Step 3 that so long as the identified NO_X emissions reduction controls are available and can be implemented (such as optimization of SCRs), they must be implemented, even as total NO_X emissions reductions on a mass basis decline. EPA's Step 3 finding is *not* limited to a determination of the mass-based reduction in emissions that the EPA determines is achievable for the covered EGU fleet under current operating conditions. Rather, the EPA finds at Step 3 that EGUs must continue to achieve NO_X emissions performance in the ozone season commensurate with the level of emissions control stringency the EPA determines appropriate under the multifactor test as set forth in this section. The stringency of the emissions budgets would simply reflect the stringency of the emissions control strategies and would do so more consistently over time than EPA's previous approach of computing emissions budgets for all future control periods at the time of the rulemaking. This retention of a constant degree of stringency over time in emissions budgets under a flexible trading program would not constitute over-control any more than the permanent imposition of emissions rate standards on individual sources at the time of the rulemaking would constitute over-control.

EPA acknowledges that this is an adjustment in its historical approach to eliminating significant contribution, although it is consistent with the evolution of the Agency's thinking as set forth in the Revised CSAPR Update. In CSAPR and the CSAPR Update, EPA established static budgets at Step 4 based on the selected level of control stringency at Step 3. EPA's experience with this approach has been that while the initial mass-based budgets are achieved and compliance targets are even exceeded, this leads to a loss in efficacy of the program as the incentive to reduce emissions declines over time. Some sources emit at higher levels or relax their operation of NO_X controls in response to the build-up of allowances available for compliance, even though EPA has concluded those controls are necessary to meet the statutory good neighbor requirements. This result is inconsistent with the statutory mandate to ''prohibit'' significant contribution and interference with maintenance of the NAAQS in other states, as evidenced most clearly in CAA section 126, which makes it unlawful for a source ''to *operate* more than three months after [a finding that the source emits or would emit in violation of the good neighbor provision] has been made with respect

[202] Included in Appendix G of the Ozone Transport Policy Analysis Proposed Rule TSD, which is available in the docket for this rulemaking.

[203] This is not to discount the potential effectiveness of these or other NO_X mitigation strategies outside the context of this rulemaking to address regional ozone transport on a nationwide basis. States and local jurisdictions may find such measures particularly impactful or necessary in the context of local attainment planning or other unique circumstances. Further, while the EPA proposes this rule as a complete remedy to the problem of interstate transport for the 2015 ozone NAAQS, the EPA has in the past recognized that circumstances may arise after the promulgation of remedies under CAA section 110(a)(2)(D)(i)(I) in which the exercise of further remedial authority against specific stationary sources or groups of sources under CAA section 126 may be warranted. *See* Response to Clean Air Act Section 126(b) Petition From Delaware and Maryland, 83 FR 50444, 50453–54 (Oct. 5, 2018).

to it.'' 42 U.S.C. 7426(c)(2) (emphasis added). Moreover, there is no policy justification at Step 3 for an upwind source to relax or cease operating its emissions controls simply because other sources of pollution have been reduced. In the Revised CSAPR Update, the EPA began to address this problem by establishing adjusted emissions budgets for each year from 2021 through 2025 based on information about the changing EGU fleet known at the time of promulgation of the rule. *See* 86 FR 23118. As discussed in Section VII.B of this proposed rule, the EPA is now implementing a more complete approach to eliminating significant contribution by imposing dynamic budget updates and banking restrictions to ensure that its selected control stringency at Step 3 continues to be implemented.

This approach at Step 4 is wholly consistent with EPA's findings at Step 3. This is best illustrated by comparing the trading program approach with the requirements the EPA could promulgate for EGUs based on an approach of assigning unit-specific emissions rate limitations. Under the latter approach, the EPA would assign an enforceable emissions rate to each EGU, based on the operation of the selected NO_X control strategy (*e.g.,* optimizing existing SCRs) that would apply in perpetuity. By continually adjusting budgets to ensure that emissions outcomes are achieved—and downwind air quality benefits are delivered—that are commensurate with the continuous operation of emissions controls at the selected control stringency at Step 3, the EPA is better aligning the implementation of the program at Step 4 with the level of emissions reductions from upwind sources that the EPA has determined is appropriate through the Step 3 multifactor analysis.[204] The EPA requests comment on its identified EGU control stringencies, including its consideration of the cost, air quality impacts, and timing of such mitigation strategies.

2. Non-EGU Assessment

The Agency prepared the non-EGU screening assessment for 2026 using the analytical framework detailed in Section VI.B.2 of this proposed rule. Using a $7,500/ton (in 2016 dollars) marginal cost threshold identified in the framework, the screening assessment used CoST with known controls, the CMDB, and the 2019 emissions inventory and estimated emissions reductions from emissions units in the Tier 1 industries and impactful boilers in the Tier 2 industries.

Using 2026 as the potential earliest date by which controls on emissions units in the Tier 1 industries and impactful boilers in the Tier 2 industries could be installed, the EPA assessed whether these emissions reduction controls should be required at Step 3 under its multi-factor test.

The EPA determined that, for 2026, the average air quality improvement at receptors relative to the EGU case when SCR post-combustion controls were installed was 0.18 ppb when Tier 1 non-EGU controls were applied and an additional 0.04 ppb when Tier 2 non-EGU controls were applied, based on the Step 3 analysis. The EPA determined for the purposes of Step 3 that all but 3 receptors remain nonattainment or maintenance after the application of these controls, with two receptors (one in Brazoria County, Texas and one in Kenosha County, Wisconsin) switching from maintenance to attainment with these non-EGU controls in place.

TABLE VI.D.2–2—AIR QUALITY AT RECEPTORS IN 2026 FROM NON-EGU INDUSTRIES

Monitor ID No.	State	County	Average DV (ppb)		Max DV (ppb)	
			Baseline (engineering analysis)	EGU SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit + non-EGU Tier 1 + Tier 2	Baseline (engineering analysis)	EGU SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit + non-EGU Tier 1 + Tier 2
40278011	Arizona	Yuma	70.11	70.06	71.81	71.76
80350004	Colorado	Douglas	70.94	70.07	71.55	70.67
80590006	Colorado	Jefferson	72.09	71.26	72.69	71.86
80590011	Colorado	Jefferson	72.97	72.16	73.68	72.86
90010017	Connecticut	Fairfield	71.60	71.35	72.30	72.04
90013007	Connecticut	Fairfield	73.09	72.54	73.99	73.43
90019003	Connecticut	Fairfield	74.83	74.40	75.03	74.59
90099002	Connecticut	New Haven	70.77	70.22	72.78	72.21
170310001	Illinois	Cook	69.05	68.73	72.87	72.53
170310032	Illinois	Cook	69.37	69.20	71.98	71.80
170310076	Illinois	Cook	68.75	68.51	71.56	71.31
170314201	Illinois	Cook	69.10	68.83	72.61	72.32
170317002	Illinois	Cook	69.36	68.98	72.27	71.88
480391004	Texas	Brazoria	70.93	68.72	73.09	70.81
482010024	Texas	Harris	76.28	74.23	77.82	75.73
490110004	Utah	Davis	72.20	71.51	74.42	73.70
490353006	Utah	Salt Lake	73.00	72.30	74.61	73.90
490353013	Utah	Salt Lake	74.10	73.34	74.60	73.84
490570002	Utah	Weber	70.30	69.63	72.22	71.53
550590019	Wisconsin	Kenosha	72.01	71.57	72.91	72.47
550590025	Wisconsin	Kenosha	68.46	67.95	71.48	70.95
551010020	Wisconsin	Racine	70.52	70.12	72.42	72.02
Average AQ Change Relative to Base (ppb)						0.64

[204] The EPA does not believe this adjustment in its Step 3 approach for EGUs, or its corresponding, improved approach to the trading program at Step 4—which, again, mimics the effect of permanent and enforceable unit-specific emissions limits—violates the prohibition on over-control. Our over-control analysis is set forth below in Section VI.D of this proposed rule, and the EPA proposes to find that there is no over-control at the proposed stringency (for both EGUs and non-EGUs) in any upwind state.

TABLE VI.D.2–2—AIR QUALITY AT RECEPTORS IN 2026 FROM NON-EGU INDUSTRIES—Continued

Monitor ID No.	State	County	Average DV (ppb)		Max DV (ppb)	
			Baseline (engineering analysis)	EGU SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit + non-EGU Tier 1 + Tier 2	Baseline (engineering analysis)	EGU SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit + non-EGU Tier 1 + Tier 2
Total PPB Change Across All Receptors Relative to Base (ppb)						14.13

For more information about how this assessment was performed and the results of the analysis for each receptor, refer to the Ozone Transport Policy Analysis Proposed Rule TSD and to the Ozone AQAT included in the docket for this rule.

a. Request for Comment on Non-EGU Control Strategies and Measures

In the non-EGU screening assessment, the EPA used CoST, the CMDB, and the 2019 emissions inventory to assess emissions reduction potential from non-EGU emissions units in several industries. The EPA identified emissions units that were uncontrolled or that could be better controlled and then applied control technologies to estimate emissions reductions and costs. As noted previously, the cost estimates do not include monitoring, recordkeeping, reporting, or testing costs. Based on the available information, the EPA is proposing to require implementation of the non-EGU emissions reductions at Step 3 by the beginning of the 2026 ozone season. The EPA discusses the basis for this proposed compliance schedule in Section VII.A.2 of this proposed rule.

The EPA requests comment on certain estimates and assumptions in this proposal that may affect EPA's evaluation of the capital and annual costs of several potential control technologies. In particular, the EPA requests comment on whether ultra-low NO_X burners or low NO_X burners are generally considered part of the process or add-on controls for ICI boilers (and how process changes or retrofits to accommodate controls would affect the cost estimates). We request comment on our estimates regarding the effectiveness of low emissions combustion in controlling NO_X from RICE compared to other potential NO_X controls for these engines. We request comment on whether controls on ICI boilers and reciprocating IC engines are likely to be run all year (*e.g.,* 8,760 hours/year) or only during the ozone season.

The EPA notes that the non-EGU NO_X mitigation strategy in this proposed rule focuses on obtaining emissions reductions from non-EGU units that were quantitatively determined to have the most significant impacts on air quality improvements at the downwind nonattainment and maintenance receptors. However, the EPA requests comment on the merits of requiring non-EGU sources within the linked upwind states to meet specified technology-based control standards, such as the RACT SIP requirements outlined in CFR part 51 for non-EGU sources located in OTR states.

3. Combined EGU and Non-EGU Assessment

The EPA used the Ozone AQAT to evaluate the combined impact of these selected stringency levels for both EGUs and non-EGUs on all receptors remaining in the 2026 air quality modeling base case to inform the over-control analysis. EPA's evaluation demonstrated air quality improvement at the 22 remaining nonattainment or maintenance receptors outside of California (*see* Section V.D of this proposed rule for receptor details). The EPA estimated that the average air quality improvement at these receptors relative to the engineering analytics base case was 0.64 ppb for emissions reductions commensurate with optimization of existing SCRs/SNCRs, combustion control upgrades, application of new post-combustion control (SCR and SNCR) retrofits at eligible units, and all estimated emissions reductions from the Tier 1 industries and impactful boilers in the Tier 2 industries. Table VI.D.1–3 summarizes the results of EPA's Step 3 evaluation of air quality improvements at these receptors using AQAT. In summary, the collective application of these mitigation measures and emissions reductions continue to deliver downwind air quality improvements up until the most stringent thresholds identified. The health and climate benefits resulting from application of these measures (as described in the RIA) are estimated to exceed the costs, and the identified technologies reflect not only demonstrated best practices—but widely adopted best practices in the case of EGU retrofits.

TABLE VI.D.3–1—CHANGE IN AIR QUALITY REDUCTIONS AT RECEPTORS IN 2026 FROM PROPOSED EGU AND NON-EGU EMISSIONS REDUCTIONS [a b c]

Tier/technology	Ozone season emissions reductions	Total PPB change across all downwind receptors [d]	Average PPB change across all downwind receptors
EGU (SCR/SNCR optimization + LNB upgrade) + Gen shifting	26,250	1.53	0.07
EGU SCR/SNCR Retrofit + Gen shifting	63,883	7.89	0.36
Non-EGU (Tier 1)	41,153	3.89	0.18
Non-EGU (Tier 2)	6,033	0.82	0.04
Total		14.13	0.64

Table Notes:

[a] As in prior rules, for the purpose of defining significant contribution at Step 3, the EPA evaluated air quality changes resulting from the application of the emissions reductions in only those states that are linked to each receptor as well as the state containing the receptor. By applying reductions to the state containing the receptor, the EPA ensures that it is accounting for the downwind state's fair share. In addition, this method holds each upwind state responsible for its fair share of the downwind problems to which it is linked. Reductions made by other states in order to address air quality problems at other receptors do not increase or decrease this share. The air quality impacts on design values that reflect the emissions reductions in all linked states and the health and climate benefits from this proposal are discussed in Section IX of this proposed rule.

[b] The EPA notes that the design values reflected in Tables VI.D.1–1 and 2 correspond to the engineering analysis EGU emissions inventory used in AQAT to determine state-level baseline emissions and reductions at Step 3. These tools are discussed in greater detail in the Ozone Transport Policy Analysis Proposed Rule TSD. Additionally, these emission reduction values vary slightly from the technology reduction estimates described in Section VI.C, as the values here reflect (1) the sum of the final identified stringency for each state (*e.g.,* SCR retrofit potential is not assumed in Alabama, Delaware, and Tennessee), and (2) generation shifting reduction potential identified at each step.

[c] The total and average ppb results from non-EGUs emissions reductions shown here were generated using the Step 3 AQAT methodology consistent with that for EGUs (*i.e.,* including reductions from the state containing the receptor and excluding states that are not explicitly linked to particular receptors). The values shown in Table VI.C.2–1 were prepared for the non-EGU screening assessment using a methodology where states within the program make emissions reductions for all receptors. States that contain receptors (*i.e.,* Connecticut and Colorado) that are not linked to other receptors are not assumed to make reductions under that methodology.

[d] The cumulative ppb change only shows the aggregate change across all problematic receptors (some of which are located within close proximity to one another) in this part of the Step 3 analysis. Section IX of this proposed rule provides a more complete picture of the air quality impacts of the proposed rule.

4. Over-Control Analysis

The EPA applied its over-control test to this same set of aggregated EGU and non-EGU data described in the previous section. As part of the air quality analysis using the Ozone AQAT, the EPA evaluated potential over-control with respect to whether (1) the expected ozone improvements would be greater than necessary to resolve the downwind ozone pollution problem (*i.e.,* beyond what is necessary to resolve all nonattainment and maintenance problems to which an upwind state is linked) or (2) the expected ozone improvements would reduce the upwind state's ozone contributions below the screening threshold (*i.e.,* 1 percent of the 2015 ozone NAAQS).

In *EME Homer City,* the Supreme Court held that the EPA cannot "require[ ] an upwind State to reduce emissions by more than the amount necessary to achieve attainment in every downwind State to which it is linked." 572 U.S. at 521. On remand from the Supreme Court, the D.C. Circuit held that this means that the EPA might overstep its authority "when those downwind locations would achieve attainment even if less stringent emissions limits were imposed on the upwind States linked to those locations." *EME Homer City II,* 795 F.3d at 127. The D.C. Circuit qualified this statement by noting that this "does not mean that every such upwind state would then be entitled to less stringent emissions limits. Some of those upwind States may still be subject to the more stringent emissions limits so as not to cause other downwind locations to which those States are linked to fall into nonattainment." *Id.* at 14–15. As the Supreme Court explained, "while EPA has a statutory duty to avoid over-control, the Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind." 572 U.S. at 523. The Court noted that "a degree of imprecision is inevitable in tackling the problem of interstate air pollution" and that incidental over-control may be unavoidable. *Id.* "Required to balance the possibilities of under-control and over-control, EPA must have leeway in fulfilling its statutory mandate." *Id.*[205]

Consistent with these instructions from the Supreme Court and the D.C. Circuit, using the Ozone AQAT, the EPA first evaluated whether reductions resulting from the selected control stringencies for EGUs in 2023 and 2026 combined with the emissions reductions selected for non-EGUs in 2026 can be anticipated to resolve any downwind nonattainment or maintenance problems (see the Ozone Policy Analysis Proposed Rule TSD for details on the construction and application of AQAT). The control stringency selected for 2023 (a representative cost threshold of $1,800 per ton for EGUs) includes emissions reductions commensurate with optimization of existing SCRs and SNCRs and installation of state-of-the-art combustion controls, which are estimated to change the status of one maintenance receptor, shifting the Clark County, Nevada monitor to attainment in 2023. However, no other nonattainment or maintenance problems would be resolved in 2023 with this level of stringency, and no state is linked solely to this receptor. Nor do any states' contribution levels drop below the 1% of NAAQS threshold. Thus, the EPA determined that none of the 26 linked states have all of their linkages resolved at the proposed EGU level of control stringency in 2023, and hence, the EPA finds no over-control in the proposed level of stringency.

Based on the air quality baseline modeling for 2026, all receptors to which Alabama, Delaware, and Tennessee are linked in 2023 are projected to be in attainment in 2026. Therefore, no additional emissions reductions are proposed for EGUs or non-EGUs in those states beyond the 2023 level of stringency. For the remaining 23 states, the selected control stringency (at a representative cost per ton threshold of $11,000 for EGUs and a marginal cost threshold of $7,500 for non-EGUs) beginning in 2026 includes additional EGU controls and estimated non-EGU emissions reductions for Tier 1 and Tier 2 non-EGU industries. The EPA used the Ozone AQAT to evaluate the impact of this selected stringency level (as well as other potential stringency levels) on all receptors remaining in the 2026 air quality modeling base case. This assessment shows that the selected control stringency level and emissions reductions are estimated to change the status of three maintenance receptors to attainment in 2026—Douglas County, Colorado; Brazoria County, Texas; and Kenosha County, Wisconsin. Based on these data, EPA proposes that at least 20 of the 23 states continue to be linked to nonattainment or maintenance receptors after implementation of all identified Step 3 reductions, and hence, the EPA finds no over-control in its determination of that level of stringency for those 20 states.

For 2 of the 23 states, Arkansas and Mississippi, the last downwind receptor to which these two states are linked (*i.e.,* Brazoria County, Texas) is estimated to achieve attainment and maintenance after full application of EGU reductions and Tier 1 non-EGU reductions. This suggests application of the estimated non-EGU emissions reductions from Tier 2 *may* constitute over-control for these states. However, this downwind

[205] Although the Court described over-control as going beyond what is needed to address "nonattainment" problems, the EPA interprets this holding as not impacting its approach to defining and addressing both nonattainment and maintenance receptors. In particular, the EPA continues to interpret the Good Neighbor provision as requiring it to give independent effect to the "interfere with maintenance" prong. *Accord Wisconsin,* 938 F.3d at 325–27.

receptor only resolves by a small margin after the application of all EGU and Tier 1 non-EGU emissions reductions. The EPA anticipates that updates to emissions inventories, emissions reduction potential from identified technologies, or the over-control test methodology resulting from comments or other updated information could possibly move this site back into nonattainment- or maintenance-receptor status when the EPA conducts an over-control analysis prior to finalizing this proposal.

For 1 of the 23 states, Wyoming, the EPA also notes a potential over-control finding under the methodological assumption where emissions reductions of commensurate stringency are assumed in the downwind state of Colorado (which is not subject to this proposal). As demonstrated in the Ozone Transport Policy Analysis Proposed Rule TSD, the last downwind receptor for Wyoming (*i.e.,* Douglas County, Colorado) is estimated to achieve attainment and maintenance after full application of EGU reductions. This suggests application of estimated non-EGU emissions reductions from Tier 1 and Tier 2 industries may constitute over-control for this state. However, when the assumption of commensurate downwind state reductions in Colorado is removed from the methodology, the downwind receptor to which Wyoming is linked does not resolve and there is no identified over-control estimated for Wyoming.[206]

Next, the EPA evaluated the potential for over-control with respect to the 1 percent of the NAAQS threshold applied in this proposed rulemaking at Step 3 of the good neighbor framework, assessed for the selected control stringencies for each state for each period that downwind nonattainment and maintenance problems persist (*i.e.,* 2023 and 2026). Specifically, the EPA evaluated whether the selected control stringencies would reduce upwind emissions to a level where the contribution from any of the 26 linked states in 2023 or 23 linked states in 2026 would be below the 1 percent threshold. The EPA finds that for the mitigation measures assumed in 2023 and in 2026, all states that contributed greater than or equal to the 1 percent threshold in the base case continued to contribute greater than or equal to 1 percent of the NAAQS to at least one remaining downwind nonattainment or maintenance receptor for as long as that receptor remained in nonattainment or maintenance. In the case of Arkansas, Mississippi, and Wyoming, while their linkages resolved based on a change in receptor status at Step 1 (as discussed above), their contribution to the relevant monitoring sites remained above 1 percent of the NAAQS, and thus, the potential basis for an over-control finding with respect to these states is not based on their contribution dropping below 1 percent of the NAAQS at those sites. For more information about this assessment, refer to the Ozone Transport Policy Analysis Proposed Rule TSD and the Ozone AQAT.

Based on these results, under no scenario does EPA's AQAT analysis for this proposal indicate that including all identified EGU reductions would constitute over-control. Rather, if these results hold for a final rule, the potential over-control for Arkansas and Mississippi can be avoided by not requiring Tier 2 non-EGU reductions, and over-control for Wyoming can be avoided by not requiring any non-EGU reductions.

Nonetheless, while acknowledging these preliminary analytic results, the EPA is proposing that all of the selected EGU and non-EGU NO_X reduction strategies selected in EPA's Step 3 analysis be applied to all linked states in 2026—including to Arkansas, Mississippi, and Wyoming—to eliminate significant contribution to nonattainment and interference with maintenance of the 2015 ozone NAAQS. The Supreme Court has directed the EPA to avoid both over-control and under-control in addressing good neighbor obligations. In addition, the D.C. Circuit has reinforced that over-control must be established based on particularized, record evidence on an as-applied basis. As noted previously, even slight changes in analytics based on comments or new information between proposal and final could result in the Brazoria, Texas site remaining either a nonattainment or maintenance receptor. Further, with respect to Wyoming, its linkage only resolves based on an unenforceable assumption regarding a certain level of emissions reduction in Colorado. The proposed determination that the stringency of this proposal does not constitute over-control for any linked state is further reinforced by EPA's observation in Section IV.A.1 of this proposed rule regarding the nature of ozone, and in particular, that future ozone concentrations and the formation of ground level ozone, may be impacted by climate change in future years.

Under these circumstances, the EPA cannot conclude based on the current record that any aspect of its selected Step 3 level of control stringency constitutes unnecessary over-control for any of the 23 states found to be linked in 2026. The EPA requests comment on this proposed conclusion. The EPA requests comment on an alternative conclusion that, if this same analysis were to persist for a final rule, it must limit non-EGU reduction requirements for Arkansas and Mississippi to only the Tier 1 industries, and for Wyoming to limit the stringency of the rule to only the EGU reduction strategies.

VII. Implementation of Emissions Reductions

A. NO_X Reduction Implementation Schedule

This proposal, if finalized, will ensure that emissions reductions necessary to eliminate significant contribution will be achieved as ''as expeditiously as practicable'' as required under CAA section 181(a). The EPA's anticipated timing will provide for all possible emissions reductions to go into effect beginning in the 2023 ozone season, which is aligned with the next upcoming attainment date of August 3, 2024, for areas classified as Moderate nonattainment under the 2015 ozone standard. Additional emissions reductions that the EPA finds not possible to implement by that attainment date are proposed to take effect as expeditiously as practicable, with the full suite of emissions reductions taking effect by the 2026 ozone season, which is aligned with the August 3, 2027, attainment date for areas classified as Serious nonattainment under the 2015 ozone NAAQS. This schedule of emissions reductions meets the requirement in the Good Neighbor Provision that it must be

[206] In this proposal, the EPA continues to assume, as it has in prior transport rules, that home-states (that are not otherwise linked) will make similar reductions as those assumed in this action for purposes of local attainment. While the EPA continues to view this to be an equitable means of assessing air quality improvement from good neighbor actions, because the downwind receptor state is assumed to do its ''fair share,'' the EPA recognizes that recent case law has called the need for such an assumption into question, and thus using this assumption as a basis for finding over-control may be inappropriate. In *Maryland,* the EPA had argued that good neighbor obligations should not be required by the Marginal area attainment deadline in part because ''marginal nonattainment areas often achieve the NAAQS without further downwind reductions, so it would be unreasonable to impose reductions on upwind sources based on the next marginal attainment deadline.'' 958 F.3d 1185, 1204. The D.C. Circuit rejected that argument, noting regulatory consequences for the downwind state for failure to attain even at the Marginal date, and, citing *Wisconsin,* the court held that upwind sources violate the good neighbor provision if they significantly contribute even at the Marginal area attainment date. *Id.* Thus, the EPA examines over-control in this proposal with and without this assumption of home-state emission reductions.

implemented ''consistent with the provisions of [title I of the CAA.]'' CAA section 110(a)(2)(D)(i). Finally, the timing of this proposed rulemaking is designed to achieve reductions as expeditiously as practicable while adhering to the procedural requirements of CAA section 110. The EPA proposes this rule to constitute a full remedy for interstate transport for the 2015 ozone NAAQS for the states covered by this proposal; the EPA does not anticipate further rulemaking to address good neighbor obligations will be required for these states with the finalization of this rule.

EPA's proposed determinations regarding the timing of this proposed rule are informed by and in compliance with several recent court decisions. The D.C. Circuit has reiterated several times since 2008 that, under the terms of the Good Neighbor Provision, upwind states must eliminate their significant contributions to downwind areas ''consistent with the provisions of [title I of the Act],'' including those provisions setting attainment deadlines for downwind areas.[207] In *North Carolina,* the D.C. Circuit found the 2015 compliance deadline that the EPA had established in CAIR unlawful in light of the downwind nonattainment areas' 2010 deadline for attaining the 1997 NAAQS for ozone and $PM_{2.5}$.[208] Similarly, in *Wisconsin,* the Court found the CSAPR Update unlawful to the extent it allowed upwind states to continue their significant contributions to downwind air quality problems beyond the downwind states' statutory deadlines for attaining the 2008 ozone NAAQS.[209] More recently, in *Maryland,* the Court found the EPA's selection of a 2023 analysis year in evaluating state petitions submitted under CAA section 126 unlawful in light of the downwind Marginal nonattainment areas' 2021 deadline for attaining the 2015 ozone NAAQS.[210] The Court noted in *Wisconsin* that the statutory command—that compliance with the Good Neighbor Provision must be achieved in a manner ''consistent with'' title I of the CAA—may be read to allow for some deviation from the mandate to eliminate prohibited transport by downwind attainment deadlines, ''under particular circumstances and upon a sufficient showing of necessity,'' but concluded that ''[a]ny such deviation would need to be rooted in Title I's framework'' and would need to ''provide a sufficient level of protection to downwind States.''[211]

1. 2023–2025: EGU NO_X Reductions Beginning in 2023

The near-term EGU control stringencies and corresponding reductions in this proposed rulemaking cover the 2023, 2024, and 2025 ozone seasons. This is the period in which some reductions will be available, but the large portion of full remedy reductions—mainly those reductions that are driven by post combustion control installation—identified in Sections VI.B through VI.D of this proposed rule are not yet available. The EGU NO_X mitigation strategies available during these initial 3 years are the optimization of existing post-combustion controls (SCRs and SNCRs) and combustion control upgrades. As described in Sections VI.B through VI.D of this proposed rule and in accompanying TSDs, these mitigation measures can be implemented in under two months in the case of existing control optimization and in 6 months in the case of combustion control upgrades.

As described in Section VI.B of this proposed rule and in the identified TSDs, these timing assumptions account for planning, procurement, and any physical or structural modification necessary. The EPA provides significant historical data, including the implementation of the most recent Revised CSAPR Update, as well as engineering studies and input factor analysis documenting the feasibility of these timing assumptions. However, these timing assumptions are representative of fleet averages, and the EPA has noted that some units will likely overperform their installation timing assumptions, while others may have unit configuration or operational considerations that result in their underperforming these timing assumptions. As in prior interstate transport rules, the EPA is implementing these EGU reductions through a trading program approach. The trading program's option to buy additional allowances provides flexibility in the program for outlier sources that may need more time than what is representative of the fleet average to implement these mitigation strategies while providing an economic incentive to outperform rate and timing assumptions for those sources that can do so. In effect, this trading program implementation operationalizes the mitigation measures as state-wide assumptions for the EGU fleet rather than unit-specific assumptions.

However, starting in 2024, as described in Section VII.B.7 of this proposed rule, unit-specific daily emissions rate limits are applied to coal units with existing SCR at a level consistent with operating that control. The EPA believes that implementing these emissions reductions at the state level starting in 2023 (through state emissions budgets) while imposing the unit-specific emissions rate limits in 2024 achieves the necessary environmental performance as soon as possible while accommodating any heterogeneity in unit-level implementation schedules regarding daily operation of optimized SCRs.

Additionally, as in prior rules, the EPA assumes combustion control upgrade implementation may take up to 6 months. In the Revised CSAPR Update, covering 12 of the 25 states for which emissions reduction requirements for EGUs are established under this proposed action, the EPA finalized the rule in March of 2021 and thus did not require these combustion control-based emissions reductions in ozone-season state emissions budgets until 2022 (year two of that program).[212] The EPA is applying the same timing assumption regarding combustion control upgrades for this proposed rulemaking given the expected similar window between an anticipated final action date and the start of the year one ozone season. The EPA is not assuming the implementation of any additional combustion control upgrades in state emissions budgets until 2024. Therefore, those 13 states covered in this action for EGU emissions reductions that were not covered in the Revised CSAPR Rule have 2023 emissions budgets that only reflect optimization of existing controls. Any identified combustion control upgrade emissions reductions are reflected beginning in the 2024 ozone-season budgets for these states. For the 12 states covered under the Revised CSAPR Update, any identified emissions reduction potential from combustion control upgrade was included and reflected in those state budgets beginning in 2022 under the Revised CSAPR Update. Therefore, the

[207] *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir. 2008), *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019), and *Maryland* v. *EPA,* 958 F.3d 1185 (D.C. Cir. 2020).

[208] *North Carolina,* 531 F.3d at 911–913.

[209] *Wisconsin,* 938 F. 3d at 303, 3018–20.

[210] *Maryland,* 958 F.3d at 1203–1204. Similarly, in *New York* v. *EPA,* 964 F.3d 1214 (D.C. Cir. 2020), the Court found the EPA's selection of a 2023 analysis year in evaluating New York's section 126 petition unlawful in light of the New York Metropolitan Area's 2021 Serious area deadline for attaining the 2008 ozone NAAQS. 964 F.3d at 1226 (citing *Wisconsin* and *Maryland*).

[211] *Wisconsin,* 938 F. 3d at 320 (citing CAA section 181(a) (allowing one-year extension of attainment deadlines in particular circumstances) and *North Carolina,* 531 F.3d at 912).

[212] 86 FR 23093.

EPA is assuming that this combustion control upgrade potential is available, if not already realized, by the first year of this action (*i.e.,* 2023) in this proposed rule.

2. 2026 and Later Years: EGU and Non-EGU NO_X Reductions Beginning in 2026

In accordance with the good neighbor provision and the downwind attainment schedule under CAA section 181 for the 2015 ozone NAAQS, the EPA is proposing to align its analysis and implementation of the emissions reductions addressing significant contribution from EGU and non-EGU sources that require relatively longer lead time at a sectoral scale with the 2026 ozone season, which is the last full ozone season preceding the August 3, 2027, Serious area attainment date for the 2015 ozone NAAQS.[213] The EPA proposes to find that this compliance deadline is the most expeditious date practicable and would achieve the required emissions reductions prior to the next applicable attainment date by which such reductions are, in fact, possible. The EPA proposes to find that it is not possible to require implementation of all necessary emissions controls across all of the affected EGU and non-EGU sources by the August 3, 2024, Moderate area attainment date.

Thus, the EPA is proposing to require compliance with the control requirements for all non-EGUs and the EGU reductions related to post-combustion control retrofit identified in this section no later than the 2026 ozone season (May through September). If finalized in early 2023, the final rule would provide more than three years for EGU and non-EGU sources to install whatever controls they deem suitable to comply with required emissions reductions by the 2026 ozone season. In addition, the publication of this proposal provides roughly an additional year of notice to these source owners and operators that they should begin engineering and financial planning now to be prepared to meet this implementation timetable.

The EPA views this timeframe for retrofitting post-combustion NO_X emissions controls and other non-EGU controls to be presumptively reasonable and achievable. A 3-year period for installation of post-combustion control technologies is consistent with the statutory timeframe for implementation of the controls required to address interstate pollution under section 110(a)(2)(D) and 126 of the Act, the statutory timeframes for implementation of RACT in ozone nonattainment areas classified as Moderate or above, and other statutory provisions that establish control requirements for existing stationary sources of pollution.

For example, section 126 of the CAA authorizes a downwind state or tribe to petition the EPA for a finding that emissions from ''any major source or group of stationary sources'' in an upwind state contribute significantly to nonattainment in, or interfere with maintenance by, the downwind state. If the EPA makes a finding that a major source or a group of stationary sources emits or would emit pollutants in violation of the relevant prohibition in CAA section 110(a)(2)(D), the source(s) must shut down within 3 months from the finding unless the EPA directly regulates the source(s) by establishing emissions limitations and a compliance schedule extending no later than three years from the date of the finding, to eliminate the prohibited interstate transport of pollutants as expeditiously as practicable.[214] Thus, in the provision that allows for direct federal regulation of sources violating the good neighbor provision, Congress established 3 years as the maximum amount of time available from a final action to when emissions reductions need to be achieved at the relevant source or group of sources.

Additionally, for ozone nonattainment areas classified as Moderate or higher, the CAA requires states to implement RACT requirements less than three years after the statutory deadline for submitting these measures to the EPA.[215] Specifically, for these areas, CAA sections 182(b)(2) and 182(f) require that states implement RACT for existing VOC and NO_X sources as expeditiously as practicable but no later than May 31, 1995, approximately 30 months after the November 15, 1992, deadline for submitting RACT SIP revisions. For purposes of the 2015 ozone NAAQS, the EPA has interpreted these provisions to require implementation of RACT SIP revisions as expeditiously as practicable but no later than January 1 of the fifth year after the effective date of designation, which is less than 3 years after the deadline for submitting RACT SIP revisions.[216] For areas initially designated nonattainment with a Moderate or higher classification effective August 3, 2018 (83 FR 25776), that implementation deadline falls on January 1, 2023, approximately 29 months after the August 3, 2020 submission deadline.[217] Moderate ozone nonattainment areas must also implement all reasonably available control measures (including RACT) needed for expeditious attainment within three years after the statutory deadline for states to submit these measures to the EPA as part of a Moderate area attainment demonstration.[218]

The EPA notes that the types and sizes of the EGU and non-EGU sources that the EPA proposes to include in this proposed rule, as well as the types of emissions control technologies on which the EPA proposes to base the

[213] For each nonattainment area classified under CAA section 181(a) for the 2015 ozone NAAQS, the attainment date is ''as expeditiously as practicable'' but not later than the date provided in table 1 to 40 CFR 51.1303(a). Thus, for areas initially designated nonattainment effective August 3, 2018 (83 FR 25776), the latest permissible attainment dates are: August 3, 2021 (for Marginal areas), August 3, 2024 (for Moderate areas), August 3, 2027 (for Serious areas), and August 3, 2033 (for Severe areas).

[214] CAA 110(a)(2)(D)(i) and 126(c).

[215] *See, e.g.,* 40 CFR 51.1112(a)(3) and 51.1312(a)(3)(i) (requiring implementation of RACT required pursuant to initial nonattainment area designations no later than January 1 of the fifth year after the effective date of designation, which is less than 3 years after the submission deadline under 40 CFR 51.1112(a)(2)) and 51.1312(a)(2)(i), respectively).

[216] 40 CFR 51.1312(a)(2)(i) (requiring submission of RACT SIP revisions no later than 24 months after the effective date of designation) and 51.1312(a)(3)(i) (requiring implementation of RACT SIP revisions as expeditiously as practicable, but no later than January 1 of the fifth year after the effective date of designation). For reclassified areas, states must implement RACT SIP revisions as expeditiously as practicable, but no later than the start of the attainment year ozone season associated with the area's new attainment deadline, or January 1 of the third year after the associated SIP revision submittal deadline, whichever is earlier; or the deadline established by the Administrator in the final action issuing the area reclassification. 40 CFR 51.1312(a)(3)(ii); *see* also 83 FR 62989, 63012–63014.

[217] 40 CFR 51.1312(a)(2)(i) (requiring submission of RACT SIP revisions no later than 24 months after the effective date of designation).

[218] *See, e.g.,* 40 CFR 51.1108(d) (requiring implementation of all control measures (including RACT) needed for expeditious attainment no later than the beginning of the attainment year ozone season, which, for a Moderate nonattainment area, occurs less than 3 years after the deadline for submission of reasonably available control measures under 40 CFR 51.1112(c) and 51.1108(a)) and 40 CFR 51.1308(d) (requiring implementation of all control measures (including RACT) needed for expeditious attainment no later than the beginning of the attainment year ozone season, which, for a Moderate nonattainment area, occurs less than three years after the deadline for submission of reasonably available control measures under 40 CFR 51.1312(c) and 51.1308(a)). Because the attainment demonstration for a Moderate nonattainment area (including RACT needed for expeditious attainment) is due three years after the effective date of the area's designation (40 CFR 51.1308(a) and 51.1312(c)), and all Moderate nonattainment areas must attain the NAAQS as expeditiously as practicable but no later than 6 years after the effective date of the area's designation (40 CFR 51.1303(a)), the beginning of the ''attainment year ozone season'' (as defined in 40 CFR 51.1300(g)) for such an area is less than three years after the due date for the attainment demonstration.

emissions limitations that would take effect for the 2026 ozone season, generally are intended to be consistent with the scope and stringency of RACT requirements for existing major sources of NO_X in downwind Moderate nonattainment areas and some upwind areas, which many states have already implemented in their SIPs.[219] Thus, the timing Congress allotted for sources in downwind states to come into compliance with RACT requirements bears directly on the amount of time that should be allotted here and indicates, as does CAA section 126, that 3 years is an outer limit on the time that should be given sources to come into compliance.

Finally, with respect to emissions standards for hazardous air pollutants, section 112(i)(3) of the CAA requires the EPA to establish compliance dates for each category or subcategory of existing sources subject to an emissions standard that ''provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard,'' with limited exceptions.[220] Here again, where Congress was concerned with addressing emissions of pollutants that impact public health, a 3-year time period was allotted as the time needed for existing sources to come into compliance.

All of these statutory timeframes for implementation of new control requirements on existing stationary sources indicate that Congress considered 3 years to be not only a sufficient amount of time but a maximum amount of time allowable for existing stationary sources to install pollution controls as necessary for expeditious attainment, to eliminate prohibited interstate transport of pollutants, and to protect public health.

Further, the EPA notes that, given the number of years that have passed since EPA's promulgation of the 2015 ozone NAAQS and related nonattainment area designations in 2018, and in light of the *Maryland* court's holding that good neighbor obligations for the 2015 ozone NAAQS should have been implemented by the Marginal area attainment date in 2021,[221] many states are substantially delayed in implementing their good neighbor obligations for these NAAQS, and the sources proposed for NO_X emissions control in this rule have continued to operate for several years without the controls necessary to eliminate their significant contribution to ongoing and persistent ozone nonattainment and maintenance problems in other states. Under these circumstances, we find it more than reasonable to require compliance with the control requirements for all non-EGUs and the EGU reductions related to post-combustion control retrofit identified in Section VI.B.1.b of this proposed rule by the beginning of the 2026 ozone season (*i.e.,* by May 1, 2026). May 1, 2026, is more than 3 years after the date by which the EPA currently anticipates promulgating a final FIP for the covered states, more than three years after the January 1, 2023, deadline for implementation of section 182 RACT SIP provisions in areas classified as Moderate or higher, and almost 8 years after the October 1, 2018, deadline for submission of good neighbor SIPs that prohibit significant contribution to nonattainment or interference with maintenance in downwind states.[222]

As the D.C. Circuit noted in *Wisconsin,* the good neighbor provision requires upwind states to ''eliminate their substantial contributions to downwind nonattainment in concert with the attainment deadlines'' in the downwind states, even where those attainment deadlines occur before EPA's statutory deadline to promulgate a FIP.[223] Referencing the Supreme Court's description of the attainment deadlines as ''the heart'' of the CAA, the *Wisconsin* court noted that some deviation from the mandate to eliminate prohibited transport by downwind attainment deadlines may be allowed only ''under particular circumstances and upon a sufficient showing of necessity,'' *e.g.,* when compliance with the statutory mandate amounts to an impossibility.[224]

For the reasons provided below in this section, the EPA is proposing to find that installation of certain EGU controls and all non-EGU controls is not possible by the Moderate area attainment date for the 2015 ozone NAAQS (*i.e.,* August 3, 2024),[225] and that the 2026 ozone season, which corresponds to the August 3, 2027, Serious area attainment date for these NAAQS, is the earliest downwind attainment date by which the required emissions reductions from these strategies are possible.

a. EGU Schedule for 2026 and Later Years

As discussed in Sections VI.B through VI.D of this proposed rule, significant emissions reduction potential exists and is included in EPA's quantification of significant contribution based on the potential to install post-combustion controls (SCR and SNCRs) at EGUs. However, as discussed in detail in those sections, the assumption for installation of this technology on a region-wide scale is 36 months in this proposed rule. This amount of time allows for all necessary procurement, permitting, and installation milestones across multiple units in the covered region. Therefore, the EPA proposes to find that these emissions reductions are not available any earlier than the 2026 compliance period. For each year in 2026 and beyond, state emissions budgets include reductions commensurate with these post-combustion control technologies identified for covered units in Step 3. The EPA notes that similar compliance schedules and post-combustion control retrofit installations have been realized successfully in prior programs allowing similar timeframes. Subsequent to the NO_X SIP Call and the parallel Finding of Significant Contribution and Rulemaking on Section 126 Petitions (which became effective December 28, 1998, and February 17, 2000, respectively [226]), nearly 19 GW of SCR

[219] *See* the Non-EGU Sectors TSD for a discussion of SIP-approved RACT rules in effect in downwind states.

[220] CAA section 112(i)(3)(B) generally authorizes the EPA to grant an extension of up to 1 additional year for an existing source to comply with emissions standards ''if such additional period is necessary for the installation of controls,'' and sections 112(i)(4) through (8) provide for limited extensions granted by the President where certain conditions are met, for existing sources that have installed the best available control technology (BACT) or technology required to meet a lowest achievable emissions rate (LAER), and for new sources for which construction or reconstruction is commenced by certain dates.

[221] 958 F.3d at 1203–1204 (remanding the EPA denial of section 126 petition based on the EPA analysis of downwind air quality in 2023 rather than 2021, the year containing the Marginal area attainment date).

[222] CAA sections 110(a)(1) and 110(a)(2)(D)(i) (requiring states to submit, within 3 years after EPA's promulgation of a new or revised NAAQS, SIP provisions adequate to satisfy the Good Neighbor Provision). As the Supreme Court noted in *EME Homer City I,* ''nothing in the statute places EPA under an obligation to provide specific metrics to States before they undertake to fulfill their good neighbor obligations.'' 572 U.S. 489, 510.

[223] 938 F.3d at 317–318. For example, the court observed that the EPA may shorten the deadline for SIP submissions under CAA section 110(a)(1) and may issue FIPs soon thereafter under CAA section 110(c)(1), to align the upwind states' deadline for satisfying good neighbor obligations with the downwind states' deadline for attaining the NAAQS. *Id.* at 318.

[224] *Id.* at 316 and 319–320 (noting that any such deviation must be ''rooted in Title I's framework'' and ''provide a sufficient level of protection to downwind States'').

[225] Compliance by the August 3, 2021, Marginal area attainment date is also impossible as that date has passed.

[226] *See* 63 FR 57356 (October 27, 1998); 65 FR 2674 (January 18, 2000). The D.C. Circuit stayed the NO_X SIP Call by an order issued May 25, 1999. After upholding the rule in most respects in *Michigan* v. *EPA,* 213 F.3d 663 (D.C. Cir. 2000), the court lifted the stay by an order issued June 22, 2000.

retrofit came online in 2002 and another 42 GW of SCR retrofit came online for steam boilers in 2003, illustrating that a considerable volume of SCR retrofit capacity is possible in a 36 month period.

However, the EPA is not proposing to apply daily emissions rates on coal-fired steam EGUs assumed to retrofit SCR until 2027 (as described in Section VII.B.1.c.i of this proposed rule). The EPA believes that implementing these emissions reductions at the state level starting in 2026 (through state emissions budgets) while imposing the unit-specific emissions rate limits in 2027 achieves the necessary environmental performance as soon as possible while accommodating any heterogeneity in unit-level implementation schedules regarding installation of new SCR.[227]

b. Non-EGU Schedule for 2026 and Later Years

For the suite of non-EGU controls on which the EPA has based its Step 3 findings as described in Section VI of this proposed rule, the EPA proposes to require that these controls be installed and operational by the 2026 ozone season and to find that any earlier date is not possible. The EPA previously examined the time necessary to install the controls identified for several non-EGU industries. Although the information on installation times for most NO_X controls applied to glass and cement manufacturing was uncertain, the EPA identified minimum estimated installation times for a number of other non-EGU source categories that ranged from several weeks to slightly over a year. This included timeframes of 42–51 weeks for SNCR applied to dry cement manufacturing facilities and cement kilns/dryers burning bituminous coal, 28–58 weeks for SCR applied to boilers and process heaters, 28–58 weeks for SCR applied to iron and steel in-process combustion, and 6–8 months for low NO_X burners and flue gas recirculation at iron and steel mills.[228] Taking into account necessary scale-up of construction services for multiple control installations at several emissions units, the time needed to have NO_X monitoring installed and operating, and other necessary steps in the permitting and construction processes (*e.g.,* review of vendor bids), the EPA estimates an additional period of 6 to 18 months may be necessary for existing non-EGU sources to install the necessary controls, depending on the number of control installations at a facility.[229]

Additionally, the EPA previously considered the installation timing needs for NO_X controls (including SCR, SNCR, and combustion controls) at both EGU and non-EGU sources as part of the 1998 NO_X SIP Call.[230] With respect to combustion controls (*e.g.,* low-NO_X burners, overfire air, etc.), the EPA found that sources should be able to complete control technology installations and obtain relevant permits in relatively short timeframes given considerable experience at that time among sources and permitting agencies with the implementation of such controls, the fact that combustion controls are constructed of commonly available materials (steel, piping, etc.) and do not require reagent during operation, and the then availability of many vendors of combustion control technology.[231]

With respect to post-combustion controls (primarily SCR and SNCR), the EPA considered three basic factors in assessing installation timing needs: (1) Availability of materials and labor, (2) the time needed to implement controls at plants with single or multiple retrofit requirements, and (3) the potential for interruptions in power supply resulting from outages needed to complete installations on EGUs.[232] Assuming adequate supplies of both off-the-shelf hardware (such as steel, piping, nozzles, pumps, and related equipment) and the catalyst used in the SCR process, as well as sufficient vendor capacity to supply retrofit SCR catalyst to sources, and taking into account the additional time needed for facility engineering review, developing control technology specifications, awarding a procurement contract, obtaining a construction permit, completing control technology design, installation, and testing, and obtaining an operating permit, the EPA found that (a) about 21 months would be needed to implement an SCR retrofit on a single unit and (b) about 19 months would be needed to implement an SNCR retrofit on a single unit.[233] The EPA also examined several particularly complicated implementation efforts and found that 34 months would be needed for a plant to install a maximum of 6 SCRs while 24 months would be needed for a plant to install a maximum of 10 SNCRs.[234] Finally, the EPA found that the necessary controls could be installed on EGUs without any disruptions in the supply of electricity because connections between a NO_X control system and a boiler can generally be completed in 5 weeks or less and thus could occur during the 5-week planned outage that each EGU typically has each year.[235]

Thus, for both EGUs and non-EGUs, EPA's technical analysis for the 1998 NO_X SIP Call indicated that a 3-year period would be sufficient for installation of both combustion and post-combustion controls, from the planning and specification of controls to completion of control technology implementation.[236] EPA's evaluation of the timeframes for post-combustion controls was based on the Agency's projection that 639 retrofit installations at EGU sources and 235 retrofit installations at non-EGU industrial sources would be necessary for existing sources in the covered states to comply with the NO_X SIP Call.[237] Although the scope of types of non-EGU sources covered by this proposed FIP is broader, and the estimated number of emissions units is greater (potentially including as many as 490 emissions units), than the scope and number of non-EGU sources evaluated in the 1998 NO_X SIP Call, and although a later analysis of timeframes for installation of post-combustion controls at EGUs produced a more refined estimate for that sector only,[238] EPA's prior analyses nonetheless inform the evaluation in this proposal of the necessary implementation schedule for non-EGU sources given they generally address NO_X control technologies similar to those that the EPA anticipates non-EGU sources may install to comply with the provisions of the proposed FIP

[227] However, as discussed in Section VII.B.1.c.i of this proposed rule, EPA's determinations in this regard are *not* based on a finding that the retrofit of post-combustion controls would not be feasible in the 2026 ozone season for all relevant units. The EPA finds that such retrofits are available and feasible on a fleetwide scale starting in the 2026 ozone season.

[228] Final Technical Support Document (TSD) for the Final Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Assessment of Non-EGU NO_X Emissions Controls, Cost of Controls, and Time for Compliance Final TSD (''CSAPR Update Non-EGU TSD''), August 2016 (Table 3), available at *https://www.epa.gov/csapr/assessment-non-egu-NOx-emission-controls-cost-controls-and-time-compliance-final-tsd.* See also Institute of Clean Air Companies, SNCR Committee, ''White Paper, Selective Non-Catalytic Reduction (SNCR) For Controlling NO_X Emissions,'' at 5 (noting that ''SNCR retrofits typically do not require extended source shutdowns'').

[229] 63 FR 57356, 57448 (October 27, 1998). EPA generally anticipates that any required permitting processes may run concurrent with other steps in the installation processes and thus may not significantly lengthen the total time needed for installation.

[230] *Id.* at 57447–57449.

[231] Id. at 57447, 57449.

[232] Id. at 57448.

[233] Id.

[234] Id.

[235] Id.

[236] Id. at 57449.

[237] Id. at 57448 (Table V–1 and Table V–2).

[238] *See* Final Report, ''Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies,'' EPA–600/R–02/073 (October 2002).

(*e.g.,* SCR, SNCR, low-NO_X burners and ultra-low NO_X burners).

Additionally, as part of EPA's evaluation of installation timing needs in the proposed CAIR (69 FR 4566), the EPA projected that it would take on average 21 months to install an SCR on one EGU unit, 27 months to install a scrubber on one EGU unit, and 3 years to install seven SCRs at a single EGU.[239] The EPA also noted that some EGUs could install SCR controls in as short of a period as 13 months.[240] This information and EPA's general experience indicate that a two-year installation timeframe for a rule requiring installation of new control technologies across a variety of emissions sources in several industries on a regional basis is a relatively fast installation timeframe, but that a 3-year installation timeframe should be feasible for most if not all of the identified industries. A shorter installation timeframe of approximately one year would likely raise significant challenges for sources, suppliers, contractors, and other economic actors, potentially including customers relying on the products or services supplied by the regulated sources. Thus, if the EPA finalizes this proposed rule in 2023, implementation of the necessary emissions controls across all of the affected non-EGU sources by the August 3, 2024, Moderate area attainment date would not be possible.

For purposes of this proposed rule, the EPA estimates that the required controls for non-EGU source categories would take up to 3 years to install across the affected industries in the 23 states that remain linked in 2026. Therefore, based on the available information, the EPA proposes to require compliance with these non-EGU control requirements by the beginning of the 2026 ozone season.

The EPA requests comment on the time needed to install the various control technologies across all of the emissions units in the Tier 1 and Tier 2 industries. In particular, the EPA solicits comment on the time needed to obtain permits (including the potential applicability of NSR requirements), the availability of vendors and materials, design, construction, and the earliest possible installation times for SCR on glass furnaces; SNCR or SCR on cement kilns; ultra-low NO_X burners, low NO_X burners, and SCR on ICI boilers (coal-fired, gas-fired, or oil-fired); low NO_X burners on large non-EGU ICI boilers; and low emissions combustion, layered emissions combustion, NSCR, and SCR on reciprocating rich-burn or lean-burn IC engines.

With respect to emissions monitoring requirements, EPA requests comment on the costs of installing and operating CEMS at non-EGU sources without NO_X emissions monitors; the time needed to program and install CEMS at non-EGU sources; whether monitoring techniques other than CEMS, such as predictive emissions monitoring systems (PEMS), may be sufficient for certain non-EGU facilities, and the types of non-EGU facilities for which such PEMS may be sufficient; and the costs of installing and operating monitoring techniques other than CEMS.

The EPA also requests comment on whether the FIP should provide a limited amount of time beyond the 2026 ozone season for individual non-EGU sources to meet the emissions limitations and associated compliance requirements, based on a facility-specific demonstration of necessity. As the D.C. Circuit stated in *Wisconsin,* the good neighbor provision may be read to allow for some deviation from the mandate to eliminate prohibited transport by downwind attainment deadlines, ''under particular circumstances and upon a sufficient showing of necessity,'' provided such deviation is ''rooted in Title I's framework [and] provide[s] a sufficient level of protection to downwind States.'' [241] Consistent with this directive, and recognizing that in general, the EPA aligns good neighbor obligations in the first instance with the last full ozone season before the downwind attainment date, the EPA requests comment on whether individual non-EGU sources should be allowed to request an extension of the May 1, 2026, compliance deadline by no more than 1 year (*i.e.,* to May 1, 2027) based on a sufficient showing of necessity. Any such comments should be supported by a detailed discussion of the facility-specific economic, technological, and other circumstances that may justify such an extension. The EPA notes that claims about infeasibility of controls are generally insufficient to justify an extension of time to comply, given the *Wisconsin* court's holding that the good neighbor provision requires upwind states to eliminate their significant contribution in accordance with the downwind states' attainment deadlines, without regard to questions of feasibility.[242]

The EPA solicits comment on the specific criteria that the EPA should apply in evaluating requests for extension of the 2026 compliance deadline for non-EGU sources. Such criteria could include documentation of inability, despite best efforts, to procure necessary materials or equipment (*e.g.,* equipment manufacturers are not able to deliver equipment before a specific date) or hire labor as needed to install the emissions control technology by 2026; documentation of installation costs well in excess of the highest representative cost-per ton threshold identified for any source (including EGUs) discussed in Section VI of this proposed rule (*e.g.,* vendor estimate showing equipment cost); documentation of a source owner or operator's inability to secure necessary financing, due to circumstances beyond the owner/operator's control, in time to complete the installation of controls by 2026; or documentation of extreme financial or technological constraints that would require the subject non-EGU emissions unit or facility to significantly curtail its operations or shut down before it could comply with the requirements of this proposed rule by 2026. Finally, the EPA requests comment on the process through which the EPA should review and act on an extension request—*e.g.,* the appropriate deadline for submitting a request, and whether the EPA should provide an opportunity for public comment before granting or denying a request.

The EPA anticipates that the owner or operator of the facility would bear the burden of establishing the necessity of an extension of time to comply, based on particular circumstances described and sufficiently documented in the submitted request. Claims of generalized financial or economic hardship or any claim that controls are not necessary to eliminate significant contribution would

[239] 69 FR 4566, 4617 (January 30, 2004) (citing Final Report, ''Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies,'' EPA–600/R–02/073 (October 2002)).

[240] Final Report, ''Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies,'' EPA–600/R–02/073 (October 2002), at 21.

[241] *Wisconsin,* 938 F. 3d at 320 (citing CAA section 181(a) (allowing one-year extension of attainment deadlines in particular circumstances) and *North Carolina,* 531 F.3d at 912).

[242] *Wisconsin,* 938 F.3d at 313–314, 319 (''When an agency faces a statutory mandate, a decision to disregard it cannot be grounded in mere infeasibility''). We note also that in the CSAPR Close-Out Rule (83 FR 65878, December 21, 2018), the EPA required no further reductions from upwind states beyond those set forth in the prior CSAPR Update based, in part, on the Agency's conclusion that it was not feasible to implement cost-effective emissions controls before 2023, 2 years after the 2021 attainment deadline for the downwind serious areas. The D.C. Circuit vacated the Close-Out Rule for its reliance on the same interpretation of the Good Neighbor Provision that the court had rejected in *Wisconsin. New York* v. *EPA,* 781 F. App'x 4 (D.C. Cir. 2019) (unpublished opinion).

not suffice to justify an extension. If the EPA finalizes a provision allowing sources to request limited extensions of time to comply, the Agency would review each request on a case-by-case basis as necessary to ensure consistency with the provisions of title I of the CAA.

B. Regulatory Requirements for EGUs

To implement the required emissions reductions from EGUs, the EPA proposes to revise the existing CSAPR NO_X Ozone Season Group 3 Trading Program (the ''Group 3 trading program'') established in the Revised CSAPR Update both to expand the program's geographic scope and to enhance the program's ability to ensure favorable environmental outcomes.[243] The EPA proposes to use a trading program for EGUs because of the inherently greater flexibility that a trading program can provide relative to more prescriptive, ''command-and-control'' forms of regulation of sufficient stringency to achieve the necessary emissions reductions. In the electric power sector, EGUs' extensive interconnectedness and coordination create the ability to shift both electricity production and emissions among units, providing a closely related ability to achieve emissions reductions in part by shifting electricity production from higher-emitting units to lower-emitting or non-emitting units. The sector's unusual flexibility with respect to how emissions reductions can be achieved makes the flexibility of a trading program particularly useful as a means of lowering the overall costs of obtaining such reductions. In addition, it is essential for the electric power sector to retain short-term operational flexibility sufficient to allow electricity to be produced at all times in the quantities needed to meet demand simultaneously, and the flexibility of a trading program can be helpful in supporting this aspect of the industry as well. As discussed later, to provide improved environmental outcomes, in this rulemaking, the EPA is proposing certain enhancements to the current provisions of the Group 3 trading program addressing environmental performance that will necessarily reduce the flexibility of the individual units participating in the program to some extent. However, with the proposed enhancements, the EPA believes the inherently greater flexibility of a trading program continues to favor the use of this form of regulation, relative to more prescriptive forms of regulation, as a vehicle for achieving the emissions reductions from the electric power sector found to be necessary in this rulemaking.

The Group 3 trading program currently applies to EGUs meeting the program's applicability criteria within the borders of twelve states: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. Affected EGUs in these twelve states would continue to participate in the Group 3 trading program as revised in this rulemaking, with some revised provisions taking effect in the 2023 control period and other revised provisions taking effect later as discussed elsewhere in this document. The EPA proposes to expand the Group 3 trading program's geographic scope to include all of the additional states for which EGU emissions reduction requirements are being established in this rulemaking. Affected EGUs within the borders of eight states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program (the ''Group 2 trading program'')—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin—would transition from the Group 2 program to the revised Group 3 trading program at the beginning of the 2023 control period,[244] and affected EGUs within the borders of the five states not currently covered by any CSAPR trading program for seasonal NO_X emissions—Delaware, Minnesota, Nevada, Utah, and Wyoming—would enter the Group 3 trading program in the 2023 control period following the effective date of a final rule in this rulemaking. As is the case for the states already in the Group 3 trading program, for each state added to the program, the set of affected EGUs would include new units as well as existing units and units located in Indian country within the state's borders as well as units not located in Indian country. Sections VII.B.2 and VII.B.3 of this proposed rule provide additional discussion of the proposed geographic expansion of the Group 3 trading program and the units in the expanded geography that would likely become subject to the program under the program's existing applicability provisions.

In addition to expanding the Group 3 trading program's geographic scope, the EPA proposes to modify the program's regulations prospectively to include certain enhancements to improve environmental outcomes. Two of the proposed enhancements would adjust the overall quantities of allowances available for compliance in the trading program in each control period so as to maintain the rule's selected control stringency and related EGU effective emissions rate performance level as the EGU fleet evolves. First, instead of establishing emissions budgets for all future years under the program at the time of the rulemaking, which cannot reflect future changes in the EGU fleet unknown at the time of the rulemaking, the EPA proposes to revise the trading program regulations to include a dynamic budgeting procedure. This procedure would calculate emissions budgets for control periods in 2025 and later years based on more current information about the composition and utilization of the EGU fleet, specifically data available from the 2023 ozone season and following (*e.g.,* for 2025, data from 2023; for 2026, data from 2024; etc.). (Associated revisions to the program's variability limits and unit-level allowance allocation procedures would coordinate these provisions with the revised budget-setting procedures.) Second, starting with the 2024 control period, the EPA proposes to annually recalibrate the quantity of accumulated banked allowances under the program to prevent the quantity of allowances carried over from each control period to the next from exceeding the target bank level, which would be revised to represent 10.5 percent of the sum of the state emissions budgets. Together, these enhancements would protect the intended stringency of the trading program against potential erosion caused by EGU fleet turnover and would better sustain over time the incentives created by the trading program to apply continuously the degree of emissions control the EPA determines is necessary to address states' good neighbor obligations.

Two further enhancements to the Group 3 trading program proposed in this rulemaking would establish provisions designed to promote more consistent emissions control by individual EGUs within the context of the trading program. First, starting with the 2024 control period for most coal-fired EGUs with existing SCR controls and the 2027 control period for most other coal-fired EGUs, a daily NO_X emissions rate of 0.14 lb/mmBtu would

[243] If any of the states whose sources currently participate in the Group 3 trading program is determined in the final rule to not have additional emissions reduction requirements for EGUs, the EPA proposes in the alternative to establish a new trading program substantially similar to the revised Group 3 trading program described in this proposal that would cover units within the borders of all the states determined to have emissions reduction requirements for EGUs in the final rule.

[244] Affected EGUs in the two other states currently covered by the Group 2 trading program—Iowa and Kansas—would continue to participate in that program.

apply as a backstop to the more stringent seasonal emissions budgets. Each ton of emissions exceeding a unit's backstop daily emissions rate would incur a 3-for-1 allowance surrender ratio instead of the usual 1-for-1 allowance surrender ratio. Second, also starting with the 2024 control period, the trading program's existing assurance provisions, which require extra allowance surrenders from sources that are found responsible for contributing to an exceedance of the relevant state's ''assurance level'' (*i.e.,* currently 121 percent of the state's emissions budget), would be strengthened by the addition of another backstop requirement. Specifically, for any unit found responsible for contributing to an exceedance of the state's assurance level, the revised regulations would prohibit the unit's seasonal emissions from exceeding by more than 50 tons the emissions that would have resulted if the unit had achieved a seasonal average emissions rate equal to the higher of 0.10 lb/mmBtu or 125 percent of the unit's lowest previous seasonal average emissions rate under any CSAPR seasonal NO_X trading program.[245]

These two enhancements are designed to ensure that all individual units with SCR controls have strong incentives to continuously operate and optimize their controls, and also to ensure that even units without SCR controls have strong incentives to optimize their emissions performance when a state's assurance level might otherwise be exceeded. These enhancements are generally designed to ensure consistency with EPA's determination regarding the emissions control stringency needed from EGUs to eliminate significant contribution under the Step 3 multifactor analysis as discussed in Section VI of this proposed rule. Further, these enhancements are designed to provide greater assurance that emissions controls will be operated on all days of the ozone season and therefore necessarily on the days that turn out to be most critical for downwind ozone levels. The EPA expects that promoting more consistently good emissions performance by individual EGUs will also help address disparate impacts of pollution on overburdened communities from individual units that might otherwise have chosen not to optimize their emissions performance.

[245] The requirement would not apply for control periods during which the unit operated for less than 10 percent of the hours, and emissions rates achieved in such previous control periods would be excluded from the comparison.

1. Trading Program Background and Overview of Proposed Revisions

a. Current CSAPR Trading Program Design Elements and Identified Concerns

The use of allowance trading programs to achieve required emissions reductions from the electric power sector has a long history, rooted in the Clean Air Act Amendments of 1990. In Title IV of those amendments, Congress specified the design elements for a 48-state allowance trading program to reduce SO_2 emissions and the resulting acid precipitation. Building on the success of that first allowance trading program as a tool for addressing multi-state air pollution issues, since 1998 EPA has promulgated and implemented multiple allowance trading programs for SO_2 or NO_X emissions to address the requirements of the CAA's good neighbor provision with respect to successively more stringent NAAQS for fine particulate matter and ozone. Most of these trading programs have applied either exclusively or primarily to EGUs.

The EPA currently administers six CSAPR trading programs for EGUs (promulgated in CSAPR, the CSAPR Update, and the Revised CSAPR Update) that differ in the pollutants, geographic regions, and time periods covered and in the levels of stringency, but that otherwise are nearly identical in their core design elements and their regulatory text.[246] The principal common design elements currently reflected in all of the programs are as follows:

- An ''emissions budget'' is established for each state for each control period, representing EPA's quantification of the emissions that would remain under certain projected conditions after elimination of the emissions prohibited by the good neighbor provision under those projected conditions. For each control period of program operation, a quantity of newly issued ''allowances'' equal to the amount of each state's emissions budget is allocated among the state's sources. (States have options to replace EPA's default allocations or to institute an auction process.) Total emissions in a given control period from all sources in the program are effectively capped at a level no higher than the total quantity of allowances available for use in the control period, consisting of the sum of all states' emissions budgets for the control period plus any unused allowances carried over from previous control periods as ''banked'' allowances.
- ''Assurance provisions'' in each program establish an ''assurance level'' for each state for each control period, defined as the sum of the state's emissions budget plus a specified ''variability limit.'' The purpose of the assurance provisions is to limit the total emissions from each state's sources in each control period to an amount close to the state's emissions budget for the control period, consistent with the good neighbor provision's mandate that required emissions reductions must be achieved within the state, while allowing some flexibility beyond the emissions budget to accommodate year-to-year operational variability. In the event a state's assurance level is exceeded, responsibility for the exceedance is apportioned among the state's sources through a procedure that accounts for the sources' shares of the state's total emissions for the control period as well as the sources' shares of the state's assurance level for the control period.
- At the program's compliance deadlines after each control period, sources are required to hold for surrender specified quantities of allowances. The minimum quantities of allowances that must be surrendered are based on the sources' reported emissions for the control period at a 1-for-1 ratio of allowances to tons of emissions (or 2-for-1 in instances of late compliance). In addition, two more allowances must be surrendered for each ton of emissions exceeding a state's assurance level for a control period, yielding an overall 3-for-1 surrender ratio for those emissions (or 4-for-1 in instances of late compliance). Failure to timely surrender all required allowances is potentially subject to penalties under the CAA's enforcement provisions.
- To continuously incentivize sources to reduce their emissions even when they already hold sufficient allowances to cover their expected emissions for a control period, and to promote compliance cost minimization, operational flexibility, and allowance market liquidity, the programs allow trading of allowances—both among sources in the program and with non-source entities—and also let allowances that are unused in one control period be carried over for use in future control periods as banked allowances. Although the programs do not directly limit either trading or banking of allowances, the 3-for-1 surrender ratio imposed by the

[246] The six current CSAPR trading programs are the CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR SO_2 Group 1 Trading Program, CSAPR SO_2 Group 2 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, and CSAPR NO_X Ozone Season Group 3 Trading Program. The regulations for the six programs are set forth at subparts AAAAA, BBBBB, CCCCC, DDDDD, EEEEE, and GGGGG, respectively, of 40 CFR part 97.

assurance provisions on any emissions exceeding a state's assurance level disincentivizes sources from relying on either in-state banked allowances or net out-of-state purchased allowances to emit over the assurance level.

- Finally, other common design elements ensure program integrity, source accountability, and administrative transparency. Most notably, each unit must monitor and report emissions and operational data in accordance with the provisions of 40 CFR part 75; all allowance allocations or auction results, transfers, and deductions must be properly recorded in EPA's Allowance Management System; each source must have a designated representative who is authorized to represent all of the source's owners and operators and is responsible for certifying the accuracy of the source's reports to the EPA and overseeing the source's Allowance Management System account; and comprehensive data on emissions and allowances are made publicly available.

The EPA continues to believe that the current CSAPR trading program structure established by the common design elements described previously has important positive attributes, particularly with respect to the exceptional degree of compliance flexibility it can provide to a sector such as the electric power sector where such flexibility is especially useful and valuable. However, the EPA also shares some stakeholders' concerns about whether the current structure, without enhancements, is capable of adequately addressing states' good neighbor obligations with respect to the 2015 ozone NAAQS in light of the rapidly evolving EGU fleet and the stringency and short-term form of the standard. One set of concerns relates to the observed tendency under the current trading programs for the supply of allowances to grow over time while the demand for allowances falls, reducing allowance prices and eroding the consequent incentives for sources to effectively control their emissions. A second, overlapping set of concerns relates to the general absence of source- or unit-specific emissions reduction requirements, allowing some individual sources to idle existing emissions controls. Emissions from these individual sources can contribute to increased pollution concentrations downwind on the particular days that matter for downwind exceedances of the relevant air quality standard and also have the potential to cause disproportionate adverse impacts on downwind overburdened communities. The EPA has analyzed hourly emissions data reported in prior cap-and-trade programs and identified instances of sources that did not operate SCR controls for substantial portions of recent ozone seasons. In an effort to maintain as much compliance and operational flexibility as possible, ensure controls happen on critically important highest ozone days, guard against this behavior under a more stringent NAAQS, and provide relief to overburdened communities, the EPA would require control operation every day through a unit-level emission rate designed to ensure reductions occur on the highest ozone days in addition to maintaining a mass-based seasonal requirement. To meet the statutory requirement to eliminate significant contribution and interference with maintenance on the critically important days, this combination of requirements would require sources to plan to run controls all season, including the highest ozone days, while giving reasonable flexibility for occasional operational needs.

In this rulemaking, the EPA is proposing to revise the Group 3 trading program to include enhancements designed to address both sets of concerns described above.[247] The principles guiding the various proposed revisions and the relationships of the revisions to one another are discussed in Sections VII.B.1.b and VII.B.1.c of this proposed rule. The individual proposed revisions are discussed in more detail in Sections VII.B.4 through VII.B.9 of this proposed rule.

b. Enhancements To Maintain Selected Control Stringency Over Time

The first set of concerns noted about the current CSAPR trading program structure relates to the programs' ability to maintain the rule's selected control stringency and related EGU effective emissions rate performance level as the EGU fleet evolves over time. Under the structure of the current CSAPR trading programs, the effectiveness of the programs at maintaining the rule's selected control stringency depends entirely on how allowance prices over time compare to the costs of sources' various emissions reduction opportunities, which in turn depends on the relationship between the supply for allowances and the demand for allowances. In considering possible ways to address concerns about the ability to enhance the current trading program structure to better sustain incentives to control emissions over time, the EPA has focused on the trading program design elements that determine the supply of allowances, specifically the approach for setting state emissions budgets and the rules concerning the carryover of unused allowances for use in future control periods as banked allowances.

i. Revised Emissions Budget-Setting Process

In each of the previous rulemakings establishing CSAPR trading programs, the EPA has evaluated the emissions that could be eliminated through implementation of certain types of emissions control strategies available at various cost thresholds to achieve certain rates of emissions per unit of heat input (*i.e.,* the amount of fuel consumed) and the effects of the resulting emissions reductions on downwind air quality. After determining the emissions control strategies and associated emissions reductions that should be required under the good neighbor provision by considering these factors in a multifactor test, the EPA has then projected the amounts of emissions that would remain after the assumed implementation of the selected emissions control strategies at various points in the future and has established the projected remaining amounts of emissions as the state emissions budgets in trading programs.

Projecting the amounts of emissions remaining after implementation of selected emissions controls necessarily requires projections not only for sources' future emissions rates but also for other factors that influence total emissions, notably the composition of the future EGU fleet (*i.e.,* the capacity amounts of different types of sources with different emissions rates) and their future utilization levels (*i.e.,* their heat input). To the extent the projections made at the time of a rulemaking for these other factors prove inaccurate, over time the emissions budgets may not reflect the intended stringency of the emissions control strategies identified in the rulemaking as consistent with addressing states' good neighbor obligations. Further, projecting EGU fleet composition and utilization has become increasingly challenging in light of the rapid evolution of the electric power sector toward more efficient and cleaner sources of generation, driven by factors including lower prices for natural gas and wind and solar generation.

[247] With the exception of the proposed conforming revisions to allowance recordation schedules discussed in Section VII.B.12 of this proposed rule, the EPA is not proposing in this rulemaking to extend the enhancements proposed for the Group 3 trading program to the other CSAPR trading programs.

A consequence of using a trading program approach with preset emissions budgets that do not keep pace with the trends in EGU fleet composition and heat input is that the preset emissions budgets maintain the supply of allowances at levels that increasingly exceed the emissions that would occur even without implementation of the emissions control strategies used as the basis for determining the emissions budgets, causing decreases in allowance prices and hence the incentives to implement the control strategies. As an example, although the emissions budgets in the CSAPR Update established in 2016 reflected implementation of the emissions control strategy of operating and optimizing existing SCR controls, within 4 years the EPA found that EGU retirements and changes in utilization not anticipated in EPA's previous budget-setting computations had made it economically attractive for at least some sources to idle or reduce the effectiveness of their existing controls (relying on purchased allowances instead).[248] While the EPA has provided analysis indicating that, on average, sources operate their controls more effectively on high electric demand days, it has also identified cases where units fail to optimize their controls on these days. Downwind states have suggested this type of reduced pollution control performance has occurred on the day and preceding day of an ozone exceedance.[249] [250] Such an outcome undermined the ongoing achievement of emissions rate performance consistent with the control strategies defined to eliminate significant contribution to nonattainment and interference with maintenance, including continuous operation and optimization of existing controls.

In the Revised CSAPR Update, the EPA took steps to better address the rapid evolution of the EGU fleet, specifically by setting updated emissions budgets for individual future years though 2024 that reflect future EGU fleet changes known with reasonable certainty at the time of the rulemaking. Some commenters requested that the EPA also update the year-by-year emissions budgets to reflect future fleet changes that might become known after the time of the rulemaking, but the EPA declined to do so, in part because no methodology for making future emissions budget adjustments in response to post-rulemaking data had been included in the proposal for the rulemaking.

Based on information available as of December 2021, it appears that the emissions budgets set for the first control period covered by the Revised CSAPR Update generally succeeded at creating incentives to operate emissions controls under the Group 3 trading program for the programs' first control period. However, the EPA recognizes that the lack of emissions budget adjustments after 2024 in conjunction with industry trends toward more efficient and cleaner resources would likely lead to a surplus of allowances after the adjustments end. In this rulemaking, besides setting new emissions budgets for the 2023 and 2024 control periods, the EPA also proposes to extend the Group 3 trading program budget-setting methodology used in the Revised CSAPR Update to routinely set emissions budgets for each future control period in the year before that control period, with each emissions budget reflecting the latest available information on the composition and utilization of the EGU fleet at the time that emissions budget is determined.

The current budget-setting methodology established in the Revised CSAPR Update and the proposed revisions are discussed in detail in Section VII.B.4 of this proposed rule and the Ozone Transport Policy Analysis Proposed Rule TSD. To summarize here, the Revised CSAPR Update's emissions budget-setting methodology includes three primary steps: (1) Establishment of a baseline inventory of EGUs adjusted for known retirements and new units, with heat input and emissions rate data for each EGU in the inventory based on recent historical data; (2) adjustment of the baseline data to reflect assumed emissions rate changes resulting from known new controls, known gas conversions, and implementation of the emissions control strategies used to determine states' good neighbor obligations; and (3) application of an increment or decrement to reflect the effect on emissions from projected generation shifting among the units in a state at the emissions reduction cost associated with the selected emissions control strategies. In this rulemaking, the EPA proposes to modify this methodology in two ways. First, the baseline EGU inventory and heat input data, but not the emissions rate data, would be updated for each control period using the most recent available reported data. For example, in early 2024, using the final data reported for 2023, the EPA would update the baseline inventory and heat input data used to determine state emissions budgets for the 2025 control period. Second, the EPA would not apply an increment or decrement to any state emissions budget for projected generation shifting associated with implementation of the selected control strategies, because any such shifting should already be reflected in the heat input data used to update the baseline.[251]

The EPA believes that the proposed revisions to the emissions budget-setting process would substantially improve the ability of the emissions budgets to keep pace with changes in the composition and utilization of the EGU fleet. The revised methodology would account for the electric power sector's overall trends toward more efficient and cleaner resources, both of which tend to decrease total heat input at affected EGUs. The revised methodology would also account for other factors that could lead to increased heat input in some states, such as generation shifting from other states or increases in electricity demand caused by rising electrification. The updating procedure would be specified in the program regulations and the computations, which would be straightforward, could be performed in a spreadsheet to deliver reliable results. EPA would provide public notice of the preliminary calculations and the data used by March 1 of the year preceding the control period and would provide an opportunity for submission of any objections to the data and preliminary calculations before finalizing the budgets for each control period by May 1 of the year before the control period to which those budgets apply. Thus, for example, sources and other stakeholders will have certainty by May 1, 2024, of the emissions budgets that will be set for the 2025 control period that starts May 1, 2025.

[248] The price of allowances in CSAPR Update states started out at levels near $800 per ton in 2017 but declined to less than $100 per ton by 2019 and were less than $70 per ton in July 2020 (data from S&P Global Market Intelligence).

[249] 86 FR 23117.

[250] *See EPA–HQ–OAR–2020–0272–0094*. ''. . . is demonstrated through examination of Maryland's ozone design value days for June 26th–28th, 2019. On those days, Maryland recorded 8-hour ozone levels of 75, 85 and 83 ppb at the Edgewood monitor. Maryland Department of the Environment evaluated the daily NO_X emission rate for units in Pennsylvania that were found to influence the design values on the 3 exceedance days (and 1 day prior to the exceedance) against the past-best ozone season 30-day rolling average optimized NO_X rate (which tends to be higher than the absolute lowest seasonal average rate).''

[251] Emission reductions derived from generation shifting will be captured in the dynamic budgets in all cases. For the pre-set budget years it is estimated and incorporated through an additional calculation step. For dynamic budget years, it is directly incorporated through the inclusion of updated heat input data reflecting observed, compliance period generation shifting.

It bears emphasis that the annually updated information would concern only the composition and utilization of the EGU fleet and not the emissions rate data also used in the emissions budget computations. The emissions budget computations for all years would reflect only the specific emissions control strategies used to determine states' good neighbor obligations as determined in this rulemaking, along with fixed historical emissions rates for units that are not assumed to implement additional control strategies, thereby ensuring that the annual updates would eliminate emissions as determined to be required under the good neighbor provision. The stringency of the emissions budgets would simply reflect the stringency of the emissions control strategies determined in the Step 3 multifactor analysis and would do so more consistently over time than EPA's previous approach of computing emissions budgets for all future control periods at the time of the rulemaking.

The proposed revisions to state emissions budgets and the budget-setting process are discussed further in Section VII.B.4 of this proposed rule. Proposed coordinated revisions to the determination of state-level variability limits and assurance levels and to unit-level allowance allocations are discussed in Sections VII.B.5 and VII.B.9 of this proposed rule, respectively.

ii. Allowance Bank Recalibration

Besides the levels of the emissions budgets, the second design element of the trading program structure that affects the supply of allowances in each control period, and that consequently also affects the ability of a trading program to maintain the rule's selected control stringency and related EGU effective emissions rate performance level as the EGU fleet evolves over time, is the set of rules concerning the carryover of unused allowances for use in future control periods as banked allowances. As noted previously, trading and banking of allowances in the CSAPR trading programs can serve a variety of purposes: Continuously incentivizing sources to reduce their emissions even when they already hold sufficient allowances to cover their expected emissions for a control period, facilitating compliance cost minimization, accommodating necessary operational flexibility, and promoting allowance market liquidity. All of these purposes are advanced by rules that allow sources to trade allowances freely (both with other sources and with non-source entities such as brokers). All of these purposes are also advanced by rules that allow unused allowances to be carried over for possible use in future control periods, thereby preserving a value for the unused allowances. However, while the EPA considers it generally advantageous to place as few restrictions on the trading of allowances as possible,[252] unrestricted banking of allowances has a potentially significant disadvantage offsetting its advantages, namely that it allows what might otherwise be temporary surpluses of allowances in some individual control periods to accumulate into a long-term allowance surplus that reduces allowances prices and weakens the trading program's incentives to control emissions. With weakened incentives, some operators would be more likely to choose not to continuously operate and optimize their emissions controls, imperiling the ongoing achievement of emissions rate performance consistent with the control strategies defined as eliminating significant contribution to nonattainment and interference with maintenance.

As discussed in detail in Section VII.B.6 of this proposed rule, the EPA is proposing to revise the Group 3 trading program by adding provisions that would establish a routine recalibration process for banked allowances that would be carried out in August 2024 and each subsequent August, after the compliance deadline for the control period in the previous year. In each recalibration, the EPA would reset the total quantity of banked allowances for the Group 3 trading program (''Group 3 allowances'') held in all Allowance Management System accounts to a target level of 10.5 percent of the sum of the state emissions budgets for the current control period. The procedure would entail identifying the ratio of the target bank amount to the total quantity of banked allowances held in all accounts before the conversion and then, if the ratio was less than 1.0, multiplying the quantity of banked allowances held in each account by the ratio to identify the appropriate recalibrated amount for the account (rounded to the nearest allowance), and deducting any allowances in the account exceeding the recalibrated amount.

The EPA believes this revision to the Group 3 trading program's banking provisions would complement the proposed revisions to the budget-setting process by ensuring that the annual bank recalibration would prevent any surplus of allowances created in one control period from diminishing the intended stringency and resulting emissions reductions of the emissions budgets for subsequent control periods.[253]

The calibration procedure would not erase the value of unused allowances for the holder, because the larger the quantity of banked allowances that is held in a given account before each recalibration, the larger the quantity of banked allowances that would be left in the account after the recalibration for possible sale or use in meeting future compliance requirements. Because the banked allowances would always have value, the opportunity to bank allowances would continue to advance the purposes served by otherwise unrestricted banking as described above. Opportunities to bank unused allowances can serve all these same purposes whether a banked allowance is of partial value (if the bank needs recalibrating to its target level) or is of full value compared to a newly issued allowance for the next control period.

The proposal to routinely recalibrate the allowance bank is discussed further in Section VII.B.6 of this proposed rule.

d. Enhancements To Improve Emissions Performance at Individual Units

The second set of concerns about the structure of the current CSAPR trading programs relates to the general absence of source- or unit-specific emissions reduction requirements. Without such requirements, the programs affect individual sources' emissions

[252] The advantages of trading programs discussed earlier in this section—providing continuous emissions reduction incentives, facilitating compliance cost minimization, and supporting operational flexibility—depend on the existence of a marketplace for purchasing and selling allowances, and broader marketplaces generally provide greater market liquidity and therefore make trading programs better at providing these advantages. The EPA recognizes that unrestricted use of *net* purchased allowances—meaning quantities of purchased allowances that exceed the quantities of allowances sold—by a source or group of sources as an alternative to making emissions reductions can interfere with the achievement of the desired environmental outcome, and Section VII.B.1.c of this proposed rule discusses the enhancements to the Group 3 trading program that the EPA is proposing in this rulemaking to reduce reliance on net purchased allowances by incentivizing or requiring better environmental performance at individual EGUs. However, the concern arises from the *use of an excessive quantity* of net purchased allowances for a particular purpose, not from the existence of a *marketplace* where allowances may be freely bought and sold.

[253] The EPA recognizes there will be a data lag inherent in the future year emissions budgets, because the budgets would reflect fleet composition and utilization data reported for a previous control period. This means that the budgets for some individual control periods may fail to fully keep pace with the EGU fleet's trends toward more efficient and cleaner resources. Nonetheless, the new approach is a substantial improvement in environmental performance of the program compared to a more unlimited approach to allowance banking.

performance only to the extent that the incentives created by allowance prices are high enough relative to the costs of the sources' various emissions control opportunities. In circumstances where the incentives to control emissions are insufficient, some individual sources even idle existing emissions controls. Emissions from these individual sources can contribute to increased pollution concentrations downwind on the particular days that matter for downwind exceedances of the relevant air quality standard and also have the potential to cause disproportionate adverse impacts on downwind overburdened communities.

This EPA intends that the trading program enhancements described in Section VII.B.1.b of this proposed rule would improve the Group 3 trading program's ability to sustain emissions control incentives over time such that needed emissions performance would be achieved by all participating units without the need for additional requirements to be imposed at the level of individual units. However, because obtaining needed emissions performance at individual units is also important, the EPA proposes to supplement the previously discussed enhancements with two other new sets of provisions that would apply to certain individual units within the larger context of the Group 3 trading program. The allowance price would continue to be the most important driver of good environmental performance for most units, but the proposed unit-level requirements would be important supplemental drivers of performance and would offer additional assurance that significant contribution is eliminated on a daily basis during the ozone season by continuous operation of existing pollution controls.

i. Unit-Specific Backstop Daily Emissions Rates

The first of the proposed trading program enhancements intended to improve emissions performance at the level of individual units is the addition of backstop daily NO_X emissions rate provisions that would apply to large coal-fired EGUs, defined for this purpose as units serving electricity generators with nameplate capacities equal to or greater than 100 MW and combusting any coal during the control period in question. Starting with the 2024 control period, a 3-for-1 allowance surrender ratio (instead of the usual 1-for-1 surrender ratio) would apply to emissions during the ozone season from any large coal-fired EGU with existing SCR controls exceeding a daily average NO_X emissions rate of 0.14 lb/mmBtu. The additional allowance surrender requirement would be integrated into the trading program as a new component in the calculation of each unit's primary emissions limitation, such that the additional allowances would have to be surrendered by the same compliance deadline of June 1 after each control period. The amount of additional allowances to be surrendered would be determined by computing, for each day of the control period, any excess of the unit's reported emissions (in pounds) over the emissions that would have resulted from combusting that day's actual heat input at an average daily emissions rate of 0.14 lb/mmBtu, summing the daily amounts, converting from pounds to tons, and multiplying by two. Starting with the 2027 control period, the 3-for-1 surrender ratio would apply in the same way to all large coal-fired EGUs, consistent with EPA's proposed determinations, first, that a control stringency reflecting installation and operation of SCR controls on all large coal-fired EGUs is appropriate to address states' good neighbor obligations with respect to the 2015 ozone NAAQS, and second, that such controls could reasonably be installed by the 2026 control period.

In prior rules addressing interstate transport of air pollution, stakeholders have noted that while seasonal cap-and-trade programs are effective at lowering ozone and ozone-forming precursors across the ozone season, attainment of the standard is measured on key days and therefore it is necessary to ensure that the rule requires emissions reductions not just seasonally, but also on those key days.[254] They have noted that while the trading programs established under the NO_X SIP Call, CAIR, and CSAPR have all been successful in ensuring seasonal reductions, states must remain below daily peak levels, not just seasonal levels, to reach attainment. These downwind stakeholder communities have suggested that operating pollution controls on the highest ozone days (and immediately preceding days) during the ozone season is of critical importance. The EPA has analyzed hourly emissions data reported in prior cap-and-trade programs and has identified instances of sources that did not operate SCR controls for substantial portions of recent ozone seasons. These instances are discussed below and in the EGU NO_X Mitigation Strategies Proposed Rule TSD in the docket. While the EPA has in prior ozone transport actions not found sufficient evidence of emissions control idling or non-operation to take the step of building in enhancements to the trading program to ensure unit-level control operation, our review of that information applied to this context suggests this problem could become more prevalent in future years relevant to this action. Rather than allow for the potential of continued deterioration in the environmental performance of our trading programs, the EPA finds the evidence of declining SCR performance in later years of trading programs sufficient to justify prophylactic measures in this proposal to ensure the emissions control strategy selected at Step 3 is indeed implemented at Step 4. Thus, particularly in the context of the more stringent 2015 ozone NAAQS combined with the full remedy nature of this action and the extended timeframe for which upwind contribution to downwind nonattainment is projected to persist, the EPA agrees with these stakeholders that the set of measures promulgated in this rulemaking to implement the control stringency levels found necessary to address states' good neighbor obligations should include measures designed to more effectively ensure that individual units operate their emission controls routinely throughout the ozone season, thereby also ensuring that the controls are planned to be in operation on the particular days that turn out to be most critical for ozone formation and for attainment of the NAAQS.[255] Routine operation of emissions controls will also provide relief to overburdened communities downwind of any units that might otherwise have chosen not to operate their controls. In the Ozone Transport TSD, the EPA conducted a screening analysis that found nearly all of the EGUs included in this analysis are located within a 24-hour transport distance of many areas with potential EJ concerns. The EPA is proposing to adopt backstop daily rate limits at the individual unit level for this purpose, implemented in the context of a trading program (*i.e.,* through enhanced allowance surrender ratios), as an alternative to adopting enforceable rate limits.

The purpose of establishing a backstop daily NO_X emissions rate and implementing it through additional

[254] EPA–HQ–OAR–2020–0272. Comment submitted by Ben Grumbles, Secretary, Maryland Department of the Environment (MDE).

[255] The CSAPR Update was a partial remedy and the Revised CSAPR Update addressed downwind nonattainment and maintenance issues that were projected to be resolved within a 4 year window. In contrast, this rule reflects a full remedy and is addressing downwind nonattainment and maintenance issues that are projected to persist for more than a decade.

allowance surrender requirements instead of as an enforceable rate limit is to incentivize improved emissions performance at the individual unit level while continuing to preserve, to the extent possible, the advantages that the flexibility of a trading program brings to the electric power sector. As discussed in Section VII.B.7 of this proposed rule, under existing trading programs without the enhancements proposed in this rulemaking, some individual coal-fired units with SCR controls have chosen to operate the controls at lower removal efficiencies than in past ozone seasons or even to idle the controls for entire ozone seasons. In addition, some SCR-equipped units have chosen to routinely cycle their emissions controls off at lower load levels, such as while operating overnight, instead of operating the controls, upgrading the units to enable the controls to be operated under those conditions, or not operating the units under those conditions.

The EPA has identified sources of interstate ozone pollution such as the New Madrid and Conemaugh plants (in Missouri and Pennsylvania, respectively) whose SCR controls were not operating for substantial portions of recent ozone seasons. The data in Figures 1 and 2 to Section VII.B.1.c.i, included in Appendix G of the Ozone Transport Policy Analysis Proposed Rule TSD available in the docket for this rulemaking, demonstrate that these units have operated their SCRs better and more consistently during years with higher NO_X allowance prices. Downwind stakeholders have noted that some of the higher emission rates (specifically in the case of Conemaugh Unit 2 in 2019) have occurred on the day of and the preceding day of an ozone exceedance in bordering states.[256]

The EPA believes that the design of the proposed daily emissions rate provisions would be effective in addressing these types of high-emitting behavior by significantly raising the cost of planned operator decisions that substantially compromise environmental performance. At the same time, the provision would not unduly penalize an occasional unplanned exceedance, because the amount of additional allowances that would have to be surrendered to address a single day's exceedance would be much smaller than the amount that would have to be surrendered to address planned poor performance sustained over longer time periods.[257]

The EPA proposes to apply the daily emissions rate provisions to large coal-fired EGUs, and not to other types of units, for reasons that are consistent with EPA's determinations regarding the appropriate control stringency for EGUs to address states' good neighbor obligations with respect to the 2015 ozone NAAQS. Installation and operation of SCR controls is well-established as best practice for control of NO_X emissions from coal-fired EGUs, as evidenced by the fact that the technology is already installed on more than 60 percent of the sector's total coal-fired capacity. In the context of the need for states to address their good neighbor obligations with respect to the 2015 ozone NAAQS, the EPA is proposing to determine that a control stringency reflecting universal installation and operation of SCR technology at large coal-fired EGUs is appropriate, based on a multi-factor test that includes consideration of cost-effectiveness along with air quality factors. Finally, where SCR controls are installed, optimized operation of those controls is an extremely cost-effective method of achieving NO_X emissions reductions. The EPA believes these considerations support establishment of the proposed daily emissions rate provisions on a universal basis for large coal-fired EGUs, with near-term application of the provisions for units that already have the controls installed and deferred application for other units, as discussed later.

With regard to gas-fired steam EGUs, SCR controls are nowhere near as prevalent, and while the EPA is proposing to include some SCR controls at gas-fired steam units in the selected control stringency, the EPA is not proposing to include universal SCR controls at gas-fired steam units. Because the EPA does not propose to determine that universal installation and operation of SCR controls at gas-fired steam EGUs is part of the selected control stringency, in order not to constrain the power sector's flexibility to choose which particular gas-fired steam EGUs are the preferred candidates for achieving the required emissions reductions, the EPA is not proposing to apply the daily emissions rate provisions to large gas-fired steam EGUs. Focusing the backstop daily emissions rates on coal-fired units is also consistent with stakeholder input which has emphasized the need for short-term rate limits at coal units given their relatively higher emissions rates.

The EPA developed the proposed level of the daily average NO_X emissions rate—0.14 lb/mmBtu—through analysis of historical data, as described in Section VII.B.7 of this proposed rule. A rate of 0.14 lb/mmBtu represents the daily average NO_X emissions rate that has been demonstrated to be achievable on approximately 95 percent of days covering more than 99 percent of total ozone-season NO_X emissions by coal-fired units with SCR controls that are achieving a seasonal NO_X average emissions rate of 0.08 lb/mmBtu (or less), which is the seasonal NO_X emissions rate that the EPA has determined is indicative of optimized SCR performance by units with existing SCR controls.

As noted previously, the daily average emissions rate provisions are proposed to apply beginning in the 2024 control period for large coal-fired units with installed SCR controls, one control period later than optimization of those controls would be reflected in the state emissions budgets under the proposal. Likewise, the daily average emissions rate provisions are proposed to apply beginning in the 2027 control period for other large coal-fired units, one control period later than emissions reductions consistent with the installation and operation of SCR controls for such units would be reflected in the state emissions budgets under the proposal. With respect to the units with existing SCR controls, not applying the daily average rate provisions until 2024 would serve two purposes. First, it would provide all the units with a preparatory interval to focus attention on improving not only the average performance of their SCR controls but also the day-to-day consistency of performance before they would be held to increased allowance-surrender consequences for exceeding the daily rate. Second, it would provide the subset of units that exhaust to common stacks with other units that currently lack SCR controls an opportunity to exercise the option to install and certify any additional monitoring systems needed to monitor the individual units' NO_X emissions rates separately; otherwise, the daily emissions rate provisions would apply to the SCR-equipped units based on the combined

[256] EPA–HQ–OAR–2020–0272–0094.

[257] While the proposed design of the daily emissions rate provision would not deter another theoretical type of poor emissions control behavior—*i.e.,* turning off emissions controls at times of peak electricity demand in order to sell the additional electricity that otherwise would have been used to run the control equipment—EPA's analysis of hourly emissions data does not show that this behavior is actually occurring. The data actually suggest the opposite—that emissions controls are generally operated better on peak demand days than on other days. *See* the Ozone Policy Analysis Proposed Rule TSD for additional details about the assessment of the tons and the Discussion of Short-term Emissions Limit document for an assessment of control operation on peak demand days.

NO_X emissions rates measured in the common stacks.[258]

With respect to the units without existing SCR controls, not applying the daily average emissions rate provisions until 2027 would also serve two purposes. First, it would provide a window for plant personnel to gain experience operating any new SCR controls, and second, it would provide some timing flexibility for any individual unit operators who fail to complete SCR control installations before the start of the 2026 control period. With respect to both sets of units, the EPA believes that the lag in applicability of one control period is permissible because the emissions budget provisions are the principal provisions intended to drive the emissions reductions required under the proposal, while the daily average emissions rate provisions are included only to backstop those provisions.

The EPA believes that the proposed unit-specific daily emissions rate provisions would strengthen the incentives for individual coal-fired units with SCR controls to operate and optimize performance of the controls. Continuous operation and optimization of post-combustion controls at individual units would help address individual days that prove in real time to be most critical for downwind ozone levels. Better continuous emissions performance by individual units would also help address disparate impacts of pollution on overburdened communities downwind from the units.

The proposed unit-specific target daily emissions rates are discussed further in Section VII.B.7 of this proposed rule.

ii. Unit-Specific Emissions Limitations Contingent on Assurance Level Exceedances

The second of the proposed trading program enhancements intended to improve emissions performance at the level of individual units is the addition of unit-specific secondary emissions limitations. The secondary emissions limitations would be determined on a unit-specific basis according to each unit's individual performance but would apply to a given unit only under the circumstance where a state's assurance level for a control period has been exceeded, the unit is included in a group of units to which responsibility for the exceedance has been apportioned under the program's assurance provisions, and the unit operated during at least 10% of the hours in the control period. Where these conditions for application of a secondary emissions limitation to a given unit for a given control period are met, the unit's secondary emissions limitation would consist of a prohibition on NO_X emissions during the control period that exceed by more than 50 tons the NO_X emissions that would have resulted if the unit had achieved an average emissions rate for the control period equal to the higher of 0.10 lb/mmBtu or 125 percent of the unit's lowest average emissions rate for any previous control period under any CSAPR seasonal NO_X trading program during which the unit operated for at least 10 percent of the hours.

The proposed secondary emissions limitation would be in addition to, not in lieu of, the primary emissions limitation applicable to each source, which would continue to take the form of a requirement to surrender a quantity of allowances based on the source's emissions, and also in addition to the existing assurance provisions, which similarly would continue to take the form of a requirement for the owners and operators of some sources to surrender additional allowances when a state's assurance level is exceeded. In contrast to these other requirements, the proposed unit-specific secondary emissions limitation would take the form of a prohibition on emissions over a specified level, such that any emissions by a unit exceeding its secondary emissions limitation would be subject to potential administrative or judicial action and subject to penalties and other forms of relief under the CAA's enforcement authorities. The reason for proposing this form of limitation is that experience under the existing CSAPR trading programs has shown that, in some circumstances, the existing assurance provisions have been insufficient to prevent exceedances of a state's assurance level for a control period even when the likelihood of an exceedance has been foreseeable and the exceedance could have been readily avoided if certain units had operated with emissions rates closer to the lower emissions rates achieved in past control periods. The assurance levels exist to ensure that emissions from each state that contribute significantly to nonattainment or interfere with maintenance of a NAAQS in another state are prohibited. *North Carolina* v. *EPA,* 531 F.3d 896, 906–908 (D.C. Cir. 2008). EPA's programs to eliminate significant contribution must therefore achieve this prohibition, and the new evidence of exceedances of the assurance provisions demonstrate that EPA's existing approach may not be sufficient to accomplish this statutory mandate.

The purpose of including assurance levels higher than the state emissions budgets in the CSAPR trading programs is to provide flexibility to accommodate operational variability attributable to factors that are largely outside of an individual owner's or operator's control, not to allow owners and operators to plan to emit at emissions rates that could be anticipated to cause a state's total emissions to exceed the state's emissions budget or assurance level. Conduct leading to a foreseeable, readily avoidable exceedance of a state's assurance level cannot be reconciled with the statutory mandate of the CAA's good neighbor provision that emissions "within the state" significantly contributing to nonattainment or interfering with maintenance of a NAAQS in another state must be prohibited. Because the current CSAPR regulations do not expressly prohibit such conduct and have proven insufficient to deter it in some circumstances, the EPA is proposing to correct the regulatory deficiency in the Group 3 trading program by adding secondary emissions limitations that cannot be complied with through the use of allowances.

The EPA notes that although the principal purpose of the proposed secondary emissions limitations is to strengthen the assurance provisions, which apply on a statewide, seasonal basis, the unit-specific structure of the new limitations would strengthen the incentives for individual units to maintain their emissions performance at levels consistent with their previously demonstrated capabilities. For units with existing post-combustion emissions controls, the new limitations would strengthen the incentives to operate and optimize the controls continuously, and for units without such existing controls, the new limitations would strengthen the incentives to minimize NO_X emissions rates through other possible measures such as improved maintenance and optimization of combustion parameters. Continuous operation of post-combustion controls and greater attention to the combustion process at individual units can be expected to reduce some individual units' emissions rates throughout the ozone season, including on the days that turn out to be most critical for downwind ozone

[258] Based on the information reported by sources to the EPA in their monitoring plans under 40 CFR part 75, five plants subject to this proposal have SCR-equipped and non-SCR-equipped coal-fired EGUs that exhaust together to common stacks: The Clifty Creek plant in Indiana; the Cooper, Ghent, and Shawnee plants in Kentucky; and the Sammis plant in Ohio.

levels. Better emissions performance on average across the ozone season by individual units would also help address disparate impacts of pollution on overburdened communities downwind from some such units.

The proposed unit-specific secondary emissions limitations are discussed further in Section VII.B.8 of this proposed rule.

2. Expansion of Geographic Scope

As part of the proposed approach for implementing the NO_X emissions reductions from EGUs identified as necessary to address various states' obligations under the good neighbor provision with respect to the 2015 ozone NAAQS, the EPA is proposing to expand the existing geographic scope of the existing CSAPR NO_X Ozone Season Group 3 Trading Program to encompass the additional states (and Indian country within the borders of such states) found to have such obligations with respect to EGUs. Specifically, the EPA is proposing to expand the Group 3 trading program to include the following states and Indian country within the borders of the states: Alabama, Arkansas, Delaware, Minnesota, Mississippi, Missouri, Nevada, Oklahoma, Tennessee, Texas, Utah, Wisconsin, and Wyoming. Any unit located in a newly added jurisdiction that meets the existing applicability criteria for the Group 3 trading program would become an affected unit under the program, as discussed in Section VII.B.3 of this proposed rule.

CSAPR, the CSAPR Update, and the Revised CSAPR Update also applied to sources in Indian country, although, when those rules were issued, no existing EGUs within the regions covered by the rules were located on lands that the EPA understood at the time to be Indian country.[259] In contrast, within the proposed geographic scope of this rulemaking, the EPA is aware of areas of Indian country within the borders of both Utah and Oklahoma with existing EGUs that would meet the program's applicability criteria. Issues related to state, tribal, and federal jurisdiction with respect to sources in Indian country in general and in these areas in particular are discussed in Section IV.C.2 of this proposed rule.

[259] CSAPR and the CSAPR Update both applied to EGUs located in areas within Oklahoma's borders that are now understood to be Indian country, consistent with the U.S. Supreme Court's decision in *McGirt* v. *Oklahoma,* 140 S. Ct. 2452 (2020) (and subsequent case law), clarifying the extent of certain Indian country within Oklahoma's borders. However, those rules were issued before the *McGirt* decision. *See* Section IV.C.2.a.

EPA's proposed approach for determining a portion of each state's budget for each control period that would be set aside for allocation to any units in areas of Indian country within the state not subject to the state's CAA implementation planning authority is discussed in Section VII.B.9 of this proposed rule.

Units in each state would join the Group 3 trading program on one of two possible dates during the program's 2023 control period (that is, the period from May 1, 2023, through September 30, 2023). The reason that two entry dates are possible is that, as discussed in Section VII.B.11 of this proposed rule, the effective date of a final rule in this rulemaking may fall after May 1, 2023. In the case of states (and Indian country within the states' borders) whose sources do not currently participate in the CSAPR NO_X Ozone Season Group 2 trading program—Delaware, Minnesota, Nevada, Utah, and Wyoming—EPA proposes that the sources would begin participating in the Group 3 trading program on the later of May 1, 2023, or the final rule's effective date. However, in the case of the states (and Indian country within the states' borders) whose sources do currently participate in the Group 2 trading program—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin—EPA proposes that the sources would begin participating in the Group 3 trading program on May 1, 2023, regardless of the final rule's effective date, subject to transitional provisions designed to ensure that the increased stringency of the Group 3 trading program as revised in this rulemaking would not substantively affect the sources' requirements prior to the rule's effective date. This approach provides a simpler transition for the sources currently covered by the Group 2 trading program than the alternative approach of being required to switch from the Group 2 trading program to the Group 3 trading program in the middle of a control period, and it is the same approach that was followed for sources that transitioned from the Group 2 trading program to the Group 3 trading program in 2021 under the Revised CSAPR Update. Section VII.B.11 of this proposed rule contains further discussion of the rationale for this approach and the specific proposed transitional provisions.

The EPA notes that under the proposed rule, the expanded Group 3 trading program would include not only the 22 states for which the EPA is proposing to determine that the required control stringency includes, among other measures, installation of new post-combustion controls, but also the three states—Alabama, Delaware, and Tennessee—for which the EPA is proposing to determine that the required control stringency does not include such measures. In previous rulemakings, the EPA has chosen to combine states in a single multi-state trading program only where the selected control stringencies were comparable, in order to ensure that states did not effectively shift their emissions reduction requirements to other states with less stringent emissions reduction requirements by using net out-of-state purchased allowances. Although the assurance provisions in the CSAPR trading programs were designed to address the same general concern about excessive shifting of emissions reduction activities between states, EPA chose not to rely on the assurance provisions as sufficient to allow for interstate trading in situations where the states were assigned differing emissions control stringencies.

In this rulemaking, the EPA believes the previous concern about the possibility that certain states might not make the required emissions reductions is sufficiently addressed through the various proposed enhancements to the design of the trading program, even where states have been assigned differing emissions control stringencies. First, the existing assurance provisions would be substantially strengthened through the addition of the unit-specific secondary emissions limitations discussed in Sections VII.B.1.c.ii and VII.B.8 of this proposed rule. Second, by ensuring that individual units operate their emissions controls effectively, the unit-specific backstop daily emissions rate provisions discussed in Sections VII.B.1.c.i and VII.B.7 of this proposed rule would necessarily also ensure that required emissions reductions occur within the state. With these enhancements to the design of the trading program, the EPA does not believe it would be necessary for sources in Alabama, Delaware, and Tennessee to be excluded from the revised Group 3 trading program simply because their emissions budgets would reflect a different selected emissions control stringency than the other states in the program.

The EPA requests comment on the proposed expansion of the geographic scope of the Group 3 trading program to include the states and areas of Indian country identified above. The EPA also requests comment on the proposed timing under which the two sets of states and Indian country within the respective states' borders would be added to the program.

3. Applicability and Tentative Identification of Newly Affected Units

The Group 3 trading program generally applies to any stationary, fossil-fuel-fired boiler or stationary, fossil fuel-fired combustion turbine located in a covered state (or Indian country within the borders of a covered state) and serving at any time on or after January 1, 2005, a generator with nameplate capacity exceeding 25 MW and producing electricity for sale, with exemptions for certain cogeneration units and certain solid waste incineration units. To qualify for an exemption as a cogeneration unit, an otherwise-affected unit generally (1) must be designed to produce electricity and useful thermal energy through the sequential use of energy, (2) must convert energy inputs to energy outputs with efficiency exceeding specified minimum levels, and (3) may not produce electricity for sale in amounts above specified thresholds. To qualify for an exemption as a solid waste incineration unit, an otherwise-affected unit generally (1) must meet the CAA section 129(g)(1) definition of a ''solid waste incineration unit'' and (2) may not consume fossil fuel in amounts above specified thresholds. The complete text of the Group 3 trading program's applicability provisions and the associated definitions can be found at 40 CFR 97.1004 and 97.1002, respectively.

The EPA is not proposing in this rulemaking to revise the existing applicability provisions for the Group 3 trading program. Thus, any unit that is located in a newly added state and that meets the existing applicability criteria for the Group 3 trading program would become an affected unit under the program. The fact that the applicability criteria for all of the CSAPR trading programs are identical therefore is sufficient to establish that any units that are currently required to participate in another CSAPR trading program in any of the proposed additional states where such other programs currently are in effect—Alabama, Arkansas, Minnesota, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin (including Indian country within the borders of such states)—would also become subject to the Group 3 trading program.

In the proposed additional states where other CSAPR trading programs are not currently in effect—Delaware, Nevada, Utah, and Wyoming (including Indian country within the borders of such states)—units already subject to the Acid Rain Program generally would also meet the applicability criteria for the Group 3 trading program, especially if the units are not capable of producing both electricity and useful thermal energy. Based on a preliminary screening analysis of the units in these states that currently report emissions and operating data to the EPA under the Acid Rain Program and that do not report the capability to produce both electricity and useful thermal energy, the Agency believes that all such units are likely to meet the applicability criteria for the Group 3 trading program.

Because the applicability criteria for the Acid Rain Program and the Group 3 trading program are not identical, it is possible that some units could meet the applicability criteria for one program but not the other. Using data reported to the U.S. Energy Information Administration, the EPA has identified 10 sources in Delaware, Nevada, Utah, and Wyoming (and Indian country within the borders of the states) with 27 units that appear to meet the general applicability criteria for the Group 3 trading program and that either (1) do not currently report NO_X emissions and operating data to the EPA under the Acid Rain Program or (2) currently report NO_X emissions and operating data to the EPA under the Acid Rain Program and also report the capability to produce both electricity and useful thermal energy. These units are listed in Table VII.B.3–1 of this proposed rule. For each of these units, the table shows the estimated historical heat input and emissions data that the EPA proposes to use for the unit when determining state emissions budgets if the unit is ultimately treated as subject to the Group 3 trading program.[260] The EPA currently lacks sufficient information to determine whether any of the units listed in the table meets all of the relevant criteria to qualify for an exemption from the Group 3 trading program as a cogeneration unit or a solid waste incineration unit.

TABLE VII.B.3–1—SELECTED EXISTING UNITS THAT COULD BE AFFECTED UNDER PROPOSAL

State	Facility ID	Facility name	Unit ID	Unit type	Estimated ozone season heat input (mmBtu)	Estimated ozone season average NO_X emissions rate (lb/mmBtu)	Notes
Delaware	591	Christiana	11	CT	1,974	0.2594	1
Delaware	591	Christiana	14	CT	1,816	0.2027	1
Delaware	52193	Delaware City Refinery	DCPP2	Boiler	872,824	0.0176	2
Delaware	52193	Delaware City Refinery	DCPP3	Boiler	2,380,430	0.0169	2
Delaware	52193	Delaware City Refinery	DCPP4	Boiler	1,374,817	0.0438	2, 3
Delaware	52193	Delaware City Refinery	MECCU1	CT	1,679,396	0.0070	2
Delaware	52193	Delaware City Refinery	MECCU2	CT	1,679,396	0.0062	2
Delaware	7153	Hay Road	1	CT	1,354,272	0.0685	1
Delaware	7153	Hay Road	2	CT	1,311,286	0.0663	1
Nevada	2322	Clark	GT4	CT	190,985	0.0475	
Nevada	2322	Clark	GT5	CT	1,455,741	0.0191	
Nevada	2322	Clark	GT6	CT	1,455,741	0.0187	
Nevada	2322	Clark	GT7	CT	1,455,741	0.0178	
Nevada	2322	Clark	GT8	CT	1,455,741	0.0204	
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val.	GTA	CT	660,100	0.0377	2, 4

[260] As discussed in Section VII.B.10.b of this proposed rule, the EPA expects that any unit that becomes subject to the Group 3 trading program pursuant to a final rule in this rulemaking and that does not already report emissions data to the EPA in accordance with 40 CFR part 75 would not be required to report emissions data or be subject to allowance holding requirements under the Group 3 trading program until May 1, 2024, because of the minimum time interval allowed for installation and certification of the required monitoring systems. Such a unit would not be taken into account for purposes of determining state emissions budgets and unit-level allocations under the Group 3 trading program until the 2024 control period. As indicated in the notes to Table VII.B.3–1 of this proposed rule, six of the listed units have reported to the Energy Information Administration that they plan to retire in 2023.

TABLE VII.B.3–1—SELECTED EXISTING UNITS THAT COULD BE AFFECTED UNDER PROPOSAL—Continued

State	Facility ID	Facility name	Unit ID	Unit type	Estimated ozone season heat input (mmBtu)	Estimated ozone season average NO_X emissions rate (lb/mmBtu)	Notes
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val.	GTB	CT	660,100	0.0387	2, 4
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val.	GTC	CT	660,100	0.0387	2, 4
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn.	GTA	CT	749,778	0.0323	2, 4
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn.	GTB	CT	749,778	0.0370	2, 4
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn.	GTC	CT	749,778	0.0364	2, 4
Nevada	56405	Nevada Solar One	HI	Boiler	479,452	0.1667	
Nevada	54271	Saguaro	CTG1	CT	1,383,149	0.0314	2
Nevada	54271	Saguaro	CTG2	CT	1,383,149	0.0301	2
Utah	50951	Sunnyside	1	Boiler	1,888,174	0.1715	
Wyoming	56312	Shute Creek	021A	CT	1,000,050	0.0081	2
Wyoming	56312	Shute Creek	021B	CT	1,000,050	0.0093	2
Wyoming	56312	Shute Creek	021C	CT	1,000,050	0.0084	2

Table notes:
[1] Unit already reports NO_X emissions and heat input data to the EPA under 40 CFR part 75 to comply with SIP requirements.
[2] Unit reports capability of producing both electricity and useful thermal energy.
[3] Unit already reports NO_X emissions and heat input data to EPA under 40 CFR part 75 for the Acid Rain Program.
[4] Unit has reported a planned retirement date of March 2023 to the Energy Information Administration.

The EPA requests comment on which existing units in Delaware, Nevada, Utah, and Wyoming and Indian country within the borders of such states would or would not meet the applicability criteria for the Group 3 trading program. In addition, with respect to each of the units listed in Table VII.B.3–1 of this proposed rule, the EPA requests comment, with supporting data, on whether the unit would or would not meet all relevant criteria set forth in 40 CFR 97.1004 and the associated definitions in 97.1002 to qualify for an exemption from the trading program as a cogeneration unit or a solid waste incineration unit (however, see Section VI.B.3 of this proposed rule). The EPA also requests comment, with supporting data, on whether the estimated historical heat input and emissions data identified for the units in Table VII.B.3–1 of this proposed rule are representative for the respective units.

4. New and Revised State Emissions Budgets

The EPA is quantifying budgets or budget formulas specific to each year to ensure that EGUs continue to be incentivized to implement the full extent of EPA's selected control stringency for future control periods. By doing so, the EPA is accounting for both scheduled and not-yet-scheduled fleet turnover in future years. For instance, if State X's budget was 5,000 tons in 2023 but there are 100 tons of emissions from a unit scheduled to retire at the end of that year and 50 tons expected from a new unit coming online by the following year, then the state emissions budget for 2024 will reflect these scheduled changes by establishing a budget of 5,000 tons − 100 tons + 50 tons = 4,950 tons for the subsequent year.

In the Revised CSAPR Update, the EPA included announced fleet changes in state emissions budgets. Several commenters applauded the merit of this approach and the importance of establishing emissions budgets that were robust to an evolving fleet while noting that ''fleet composition is changing constantly and can be exceedingly difficult to project'' leading to overstated emissions budgets to the extent that future retirements were not announced at the time of rule promulgation. Commenters added that ''to address this problem and prevent future unknown retirements from exacerbating this issue, the final rule should include a provision to make additional adjustments to the NO_X budgets based on newly discovered fleet changes.'' [261] Commenters were suggesting a dynamic budget approach where the mitigation measures and control stringencies that constituted removal of significant contribution would be identified in a final rule, but the future year state budgets would be dynamic as the EPA applied those stringency assumptions to future year fleet composition data as it became available. While the stringency (reflected by assumed emissions rate for a mitigation technology), would be constant, the fleet composition (reflected by unit heat input) is dynamic. Multiplying the assumed emissions rate for each unit by the heat input for each unit and summing the results to the state level would provide a given year's state emissions budget, and thus under this approach the state emissions budgets would be dynamic as well.

The EPA is proposing a dynamic budget approach in this rule, where emissions budgets starting in the 2025 control period and beyond will be determined through ministerial actions subsequent to this rule's promulgation and based upon the formula described in this rule. This rule will determine the mitigation strategies, respective emissions rates, and formulas and methodologies to be applied to future year data, with which the EPA will perform ministerial actions to calculate emissions budgets for control periods in 2025 and each year thereafter. (Such actions will be publicly announced through notices of data availability (NODAs), similar to how other periodic ministerial actions to implement the trading programs are currently handled. And as with such other actions, interested parties will have the opportunity to seek corrections or administrative adjudication under 40 CFR part 78 if they believe any data used in making these calculations, or the calculations themselves, are in error.) In this manner, the state emissions budgets ultimately implemented for each such future control period will be a product of the data and formula promulgated in this

[261] EPA–HQ–OAR–2020–0272–0094.

action applied to future year reported data that is closer to that future control period and therefore more representative of the fleet for that future control period. As such, the budgets will more accurately reflect power sector composition in that future year and will therefore better achieve the desired environmental outcome over time.

For instance, 2025 budgets will be identified by May 1, 2024, using the latest available reported operational data at that time (2023 heat input data and fleet inventory) along with the formulas and emissions rates quantified in this rule. Therefore, if a unit retires in early 2023 but had not announced its upcoming retirement at the time of rule finalization, the dynamic budget approach would ensure that the budgets for future control periods starting in 2025 would reflect the identified control stringency applied to a fleet that reflects that retirement. If the EPA took an alternative approach of computing the 2025 budget with available data at the time final rule analysis was being conducted, this retirement would likely not be captured in the 2025 state emissions budget, which would lead to a budget that did not fully reflect the application of the identified control stringency. This approach has the advantage of mitigating uncertainty regarding future retirements, new builds, and existing fleet operational/dispatch changes in response to EGU inventory changes.

The example below illustrates the effectiveness of the dynamic budget. In the preset budget approach for 2026, the 2026 heat input is estimated based on the latest available heat input data at the time of rule promulgation (*e.g.,* 2021), which cannot reflect a subsequent fleet change in heat input values (column 2) due to an unanticipated retirement of one of the state's coal-fired units in late 2023. However, the dynamic budget would use 2024 heat input values as opposed to the 2021 heat input values as the latest representative values to inform the 2026 state emissions budget. Therefore, the heat input values in column 2 under the dynamic scenario reflect the change in fleet composition, and when multiplied by the relevant identified control stringency (to be identified when this rule is finalized), the corresponding tonnage (15,000 tons) summed in column 4 constitutes a state budget that better reflects the identified control stringency applied to the fleet composition for that year as opposed to the 17,000 tons in summed in the first table. As illustrated in the example, the dynamic variable is the heat input variable which changes over time to reflect the most representative EGU fleet.

	Preset Budget Appraoch (2026)			Dynamic Budget Approach (2026)		
	Preset Heat Input (tBtu)	Preset Emissions Rate (lb/mmBtu)	Preset Tons (Heat input X Emissions Rate)/2000	Updated Heat Input (tBtu)	Emissions Rate (lb/mmBtu)	Updated Tons (Heat Input X Emissions Rate)/2000
Coal Units	600	0.05	15,000	500	0.05	12,500
Gas Units	400	0.01	2,000	500	0.01	2,500
State Budget (tons)			**17,000**			**15,000**

The EPA requests comment on this dynamic budget approach, including the methodology, the start year, and the impacts.

With regard to the state emissions budgets for the 2023 and 2024 control periods promulgated in this rule, the EPA is using the best available data at the time of the proposed rule regarding retirements and new builds. The EPA relies on a compilation of data from DOE EIA Form 860 (where facilities report their future retirement plans) and information included in the Agency's NEEDS database. This information is considered to be highly reliable, real-world information that provides the EPA with high confidence that such retirements will in fact occur. EPA plans to update this data on retirements and new builds at final rule using the latest information available from these sources at that time as well as input provided by commenter.

EPA's emissions budget methodology and formula for establishing Group 3 budgets are described in detail in the Ozone Transport Policy Analysis Proposed Rule TSD and summarized below.

a. Methodology for Determining Preset State Emissions Budgets for the 2023 and 2024 Control Periods

For determining state emissions budgets, the EPA generally uses historical ozone season data from the 2021 ozone season, the most recent data and therefore the most representative of near-term fleet conditions. This is similar to the approach taken in the CSAPR Update where the EPA began with 2015 data (the most recent year at the time). As in the CSAPR Update, the EPA combined historical data with IPM data to determine emissions budgets as follows:

(1) Determine a future year baseline—Start with the latest reported historical unit-level data (*e.g.,* 2021), and adjust any unit data where a retirement, a new build, a coal-to-gas conversion, or a SCR retrofit is known to occur by the baseline year. This results in a future year (*e.g.,* 2023) baseline for emissions budget purposes.

(2) Factor in additional emissions controls for the selected control stringency for the given state in the given year—For the unit-level emissions control technologies identified in this control stringency, adjust the baseline unit-level emissions and emissions rates. For example, if an SCR-controlled coal unit had a baseline emissions rate greater than 0.08 lb/mmBtu, its emissions rate and corresponding emissions would be adjusted down to levels reflecting its operation at 0.08 lb/mmBtu.

(3) Incorporate generation shifting—Use IPM in a relative way to capture the reductions expected from generation shifting (constrained to within each state) at the representative dollar per ton level corresponding to the selected control stringency.

By using historical unit and state-level NO_X emissions rates, heat input, and emissions data in the first stage of budget setting process outlined above, the EPA is grounding its budgets in the most recent representative historical operation for the covered units.[262] This dataset is a reasonable starting point for

[262] The EPA notes that historical state-level ozone season EGU NO_X emissions rates are publicly available and quality assured data. They are monitored using CEMS or other methodologies allowed for use by qualifying units under 40 CFR part 75 and are reported to the EPA directly by power sector sources.

the budget-setting process as it reflects the latest data reported by affected facilities under 40 CFR part 75. The reporting requirements include quality control measures, verification measures, and instrumentation to best record and report the data. In addition, the designated representatives of EGU sources are required to attest to the accuracy and completeness of the data. The EPA adjusted the 2021 ozone-season data to reflect committed fleet changes under a baseline scenario (*i.e.,* announced and confirmed retirements, new builds, and retrofits that have already occurred). For example, if a unit emitted in 2021, but retired in 2022, its 2021 emissions would not be included in the 2023 baseline estimate. For units that had no known changes, the 2023 baseline emissions assumption was the actual reported data from 2021. The EPA also included known new units and scheduled retrofits in this manner. Using this method, the EPA arrived at a baseline emission, heat input, and emissions rate estimate for each unit for a future year (*e.g.,* 2023), and then was able to aggregate those unit-level estimates to state-level totals. These state-level totals constituted the state's baseline from an engineering analytics perspective. The ozone-season state-level emissions, heat input, and emissions rates for covered sources under a baseline scenario were determined for each future year examined that receives a preset budget under this proposed rule (2023 and 2024).

The EPA then examined how the baseline emissions and emissions rates would change under different control stringencies for EGUs. For instance, under the SCR optimization scenario, if a unit was not operating its SCR at 0.08 lb/mmBtu or lower in the baseline, the EPA lowered that unit's assumed emissions rate to 0.08 lb/mmBtu and calculated the impact on the unit's and state's emissions rate and emissions. Note that the heat input is held constant for the unit in the process, reflecting the same level of unit operation compared to historical 2021 data. An improved emissions rate is then applied to this heat input, reflecting control optimization. In this manner, the state-level baseline totals reflecting known changes were adjusted to reflect the additional application of the assumed control technology at a given control stringency.

Finally, the EPA used IPM to capture any generation shifting at a given control stringency necessary for the majority of the respective emissions control technology to operate. The EPA explains how it accounts for generation shifting in more detail in Section VI.B of this proposed rule and in the Ozone Transport Policy Analysis Proposed Rule TSD. In this rule, as a proxy for the near-term reductions required in 2023 and 2024, the EPA has constrained generation shifting to occur only within-state. The EPA also estimates emissions reductions associated with generation shifting in 2025 and 2026 for purposes of the illustrative state budgets, but as explained below, the dynamic budget process to determine budgets for those years will incorporate emissions reductions attributable to generation shifting through the inclusion of newly reported unit-level data from the future compliance periods.

b. Methodology for Determining Dynamic State Emissions Budgets for Control Periods in 2025 Onwards

The methodology for determining state emissions budgets for later control periods (2025 and beyond) is nearly identical to the process for quantifying preset budgets in 2023 and 2024 described earlier; it is just applied at a later date and applied to the most recent representative operational available at that time. The EPA will issue by ministerial action these dynamic budget quantifications approximately 1 year before the relevant control period. For instance, starting in early 2024, the EPA would take the most recent 2023 ozone season data, calculate 2025 state emissions budgets using the methodology below and update its unit-level and state-level state emissions budget files that will be released when this rule is finalized (and for which the EPA has included in this proposed rule current examples for public comment). By March 1 of 2024, and each year thereafter, the EPA would make publicly available (in manner similar to data and preliminary computations for allocations from new unit set-asides) the preliminary state emissions budgets and unit-level allocations for the subsequent control period (*e.g.,* 2025) and would provide stakeholders with a 30-day opportunity to submit any objections to the updated data and computations. By May 1 of 2024, and each year thereafter, the EPA would issue the final budgets and allowance allocations for the next control period (*e.g.,* 2025).

The differences to each of the formula steps to calculate dynamic budgets for control periods in 2025 and beyond, relative to the calculation of preset budgets for the 2023 and 2024 control periods, are described later:

(1) Determine a future year baseline—At this step, the EPA would start with the latest reported historical unit-level heat input data available at that time (*e.g.,* for 2025 state emissions budgets, the EPA would use the newly available 2023 heat input data rather than 2021 heat input data). Doing so would capture the latest operational data reflecting new builds and retirements. This would yield a future year (*e.g.,* 2025) baseline for emissions budget purposes.

(2) Factor in additional emissions controls for the selected control stringency for the given state in the given year—For the unit-level emissions reduction measures identified in the selected control stringency, adjust the baseline unit-level emissions and emissions rates. This step would be nearly the same for control periods in 2025 and beyond as for the 2023 and 2024 control periods, the only difference being that as described in Section VI.D of this proposed rule, for each control period from 2026 onward, the unit-specific emissions rates assumed for all affected states except Alabama, Delaware, and Tennessee will reflect the selected control stringency that incorporates post-combustion control retrofit opportunities for the relevant units identified in the state emissions budgets and calculations appendix to the Ozone Transport Policy Analysis Proposed Rule TSD. These rates would be defined in this rule and would not change subsequently. They would not be applied until 2026, based on the time necessary to install these mitigation technologies as discussed in Sections VI.B, VI.C, and VII.A of this proposed rule.

(3) Incorporate generation shifting—This step would be automatically captured in dynamic budget calculations as generation shifting in a compliance scenario would no longer have to be projected by IPM and incorporated into the state budgets through an additional calculation. Instead, it would be embodied in the newly reported heat input data described above and that is used to determine the dynamic budgets.

Additional details, corresponding data and formulas, and examples for the dynamic budget are described in the Ozone Transport Policy Analysis Proposed Rule TSD.

c. Proposed and Illustrative State Emissions Budgets

For each covered state (and Indian country within the state's borders), preset budgets are established for the two individual control periods 2023 and 2024. For 2025 and beyond, the dynamic budget formula promulgated in this proposed rule would be applied to future year data to quantify state emissions budgets for those control periods. The proposed default procedures for allocating the allowances from each state budget among the units in each state (and Indian country within the state's borders) are described in Section VII.B.9 of this proposed rule. The amounts of the proposed state emissions budgets for the 2023 and 2024 control periods are shown in Table VII.B.4.c–1. Table VII.B.4.c–2 shows illustrative state emissions budgets for the 2025 and 2026 control periods derived by applying the identified control stringency to the most recent historical data, but these budgets are only illustrative because, under the proposal, the implemented state emissions budgets for these years will be determined at a future date through application of the proposed budget-setting methodology to data that reflect the emissions control stringencies finalized in the rulemaking combined with the latest available data on the composition and utilization of the EGU fleet.

TABLE VII.B.4.c–1—PROPOSED CSAPR NO_X OZONE SEASON GROUP 3 STATE EMISSIONS BUDGETS FOR THE 2023 AND 2024 CONTROL PERIODS [a b]

State	Proposed emissions budgets for 2023 control period (tons)	Proposed emissions budgets for 2024 control period (tons)
Alabama	6,364	6,306
Arkansas	8,889	8,889
Delaware	384	434
Illinois	7,364	7,463
Indiana	11,151	9,391
Kentucky	11,640	11,640
Louisiana	9,312	9,312
Maryland	1,187	1,187
Michigan	10,718	10,718
Minnesota	3,921	3,921
Mississippi	5,024	4,400
Missouri	11,857	11,857
Nevada	2,280	2,372
New Jersey	799	799
New York	3,763	3,763
Ohio	8,369	8,369
Oklahoma	10,265	9,573
Pennsylvania	8,855	8,855
Tennessee	4,234	4,234
Texas	38,284	38,284
Utah	14,981	15,146
Virginia	3,090	2,814
West Virginia	12,478	12,478
Wisconsin	5,963	5,057
Wyoming	9,125	8,573

Table Notes:

[a] The state emissions budget calculations pertaining to Tables VII.B.4.c–1 and VII.B.4.c–2 are described in greater detail in the Ozone Transport Policy Analysis Proposed Rule TSD. Budget calculations and underlying data are also available in Appendix A of that TSD.

[b] In the event a final rule in this rulemaking becomes effective after May 1, 2023, the emissions budgets and assurance levels for the 2023 control period would be adjusted under the rule's proposed transitional provisions to ensure that the increased stringency of the new budgets would apply only after the rule's effective date, even though the revised Group 3 trading program would be implemented for most sources as of the start of the 2023 ozone season on May 1, 2023. The 2023 budget amounts shown in Table VII.B.4.c–1 do not reflect these possible adjustments. The transitional provisions are discussed in Section VII.B.11 of this proposed rule.

TABLE VII.B.4.c–2—ILLUSTRATIVE CSAPR NO_X OZONE SEASON GROUP 3 STATE EMISSIONS BUDGETS FOR THE 2025 AND 2026 CONTROL PERIODS

State	Illustrative emissions budgets for 2025 control period (tons)	Illustrative emissions budgets for 2026 control period (tons)
Alabama	6,306	6,306
Arkansas	8,889	3,923
Delaware	434	434
Illinois	7,463	6,115
Indiana	8,714	7,791
Kentucky	11,134	7,573
Louisiana	9,179	3,752
Maryland	1,187	1,189
Michigan	10,759	6,114
Minnesota	3,910	2,536
Mississippi	4,400	1,914
Missouri	10,456	7,246
Nevada	2,372	1,211
New Jersey	799	799
New York	3,763	3,238
Ohio	8,369	8,586
Oklahoma	9,393	4,275
Pennsylvania	8,855	6,819
Tennessee	4,008	4,008

TABLE VII.B.4.c–2—ILLUSTRATIVE CSAPR NO_X OZONE SEASON GROUP 3 STATE EMISSIONS BUDGETS FOR THE 2025 AND 2026 CONTROL PERIODS—Continued

State	Illustrative emissions budgets for 2025 control period (tons)	Illustrative emissions budgets for 2026 control period (tons)
Texas	36,619	21,946
Utah	15,146	2,620
Virginia	2,948	2,567
West Virginia	12,478	10,597
Wisconsin	4,198	3,473
Wyoming	8,573	4,490

5. Variability Limits and Assurance Levels

Like each of the other CSAPR trading programs, the Group 3 trading program currently includes assurance provisions designed to limit the total emissions from the sources in each state (and Indian country within the state's borders) in each control period to an amount close to the state's emissions budget for the control period, consistent with the good neighbor provision's requirement that required emissions reductions must be achieved within the state, while allowing some flexibility beyond the emissions budget to accommodate year-to-year operational variability beyond sources' reasonable ability to control. For each state, the assurance provisions establish an assurance level for each control period, defined as the sum of the state's emissions budget for the control period plus a variability limit, which under the existing Group 3 trading program regulations is 21 percent of the relevant state emissions budget. The purpose of the variability limit is to account for year-to-year variability in EGU operations, which can occur for a variety of reasons including changes in weather patterns, changes in electricity demand, and disruptions in electricity supply from other units or from the transmission grid. Because of the need to account for such variability in operations of each state's EGUs, the fact that emissions from the state's EGUs may exceed the state's emissions budget for a given control period is not treated as inconsistent with satisfaction of the state's good neighbor obligations as long as the total emissions from the EGUs remain below the state's assurance level. Emissions from a state's EGUs above the state's emissions budget but below the state's assurance level are treated in the same manner as emissions below the state's emissions budget in that such emissions are subject to the same requirement to surrender allowances at a ratio of one allowance per ton of emissions. In contrast, emissions above the state's assurance level for a given control period are strongly discouraged as inconsistent with the state's good neighbor obligations and are subject to an overall 3-for-1 allowance surrender ratio. The establishment of assurance levels with associated extra allowance surrender requirements was intended to respond to the D.C. Circuit's holding in *North Carolina* requiring the EPA to ensure within the context of an interstate trading program that sources in each state are required to address their good neighbor obligations within the state and may not simply shift those obligations to other states by failing to reduce their own emissions and instead surrendering surplus allowances purchased from sources in other states.[263]

In this rulemaking, the EPA is not proposing to alter the basic structure of the Group 3 trading program's assurance provisions, which would continue to set an assurance level for each control period equal to the state's emissions budget for the control period plus a variability limit and would continue to apply a 3-for-1 surrender ratio to emissions exceeding the state's assurance level.[264] Each assurance level also would continue to apply to the collective emissions of all units within the state and Indian country within the state's borders.[265] For the 2023 and 2024 control periods, the EPA proposes to retain the Revised CSAPR Update's methodology for determining each state's variability limit as 21 percent of the state's emissions budget for the control period, except that because the EPA is proposing to revise the state emissions budgets for these control periods, the EPA proposes to determine the corresponding variability limits as 21 percent of the revised budgets. However, for control periods after 2024, the EPA is proposing a change to the methodology for determining the variability limits. Specifically, the EPA proposes to determine each state's variability limit for the control periods in 2025 or a later year so that, instead of always multiplying the state's emissions budget for the control period by a value of 21 percent, the percentage value used would be the higher of 21 percent or the percentage (if any) by which the total reported heat input of the state's affected EGUs in the control period exceeds the total reported heat input of the state's affected EGUs as reflected in the state's emissions budget for the control period. For example, if the total reported heat input of the state's covered sources for the 2025 control period was 90 percent or 110 percent of the total reported heat input of the state's covered sources for the 2023 control period (*i.e.,* the heat input the EPA would have used in computing the state's 2025 emissions budget), then the state's variability limit for the 2025 control period would be 21 percent of the state's emissions budget, while if the total reported heat input of the state's covered sources for the 2025 control period was 130 percent of the total reported heat input of the state's covered sources for the 2023 control period, then the state's variability limit for the 2025 control period would be 30 percent of the state's emissions budget. The EPA expects that the minimum 21 percent would apply in almost all instances, and that the alternative, higher percentage value would apply only in control periods where operational variability caused an extreme increase relative to the earlier year used in setting the state's emissions budget, which would be a situation

263 531 F.3d at 908.

264 As discussed in Section VII.B.8 of this proposed rule, the EPA is also proposing to establish a new secondary emissions limitation for individual units that would apply in situations where an exceedance of the relevant state's assurance level has occurred.

265 *See* 40 CFR 97.1002 (definitions of ''common designated representative,'' ''common designated representative's assurance level'' and ''common designated representative's share''), 97.1006(c)(2), and 97.1025.

meriting a temporarily higher variability limit and assurance level.

The purpose of the proposed revision to the variability limits is to better align the variability limits for successive control periods with the regularly updated heat input data that would be used in the proposed process for dynamically setting the state emissions budgets. Under EPA's proposed budget-setting process, each emissions budget would be computed using the latest available reported heat input, which for each budget set for a control period in 2025 or a later year would be the heat input for the control period two years before the control period whose budget is being determined (for example, the state emissions budgets for the 2025 control period would be computed in early 2024 using the reported heat input for the 2023 control period). The proposed revised variability limits would be well coordinated with the budgets established using this dynamic budgeting process, because the percentage change in the actual heat input for the control period relative to the earlier-year heat input used in computing the state's emissions budget would be an appropriate measure of the degree of operational variability actually experienced by the state's EGUs in the control period relative to the assumed operating conditions reflected in the state's budget. Setting a variability limit in this manner would be entirely consistent with the overall purpose of including variability limits in the assurance provisions.

The reason the EPA is proposing to use the higher of a fixed 21% or the percentage change in heat input computed as just described is that the EPA believes that, for operational planning purposes, it can be useful for sources to know in advance of the control period a minimum value for what the variability limit could turn out to be. Because a state's actual total heat input for a control period is not known until after the end of the control period, this proposed revision would have the consequence that the state's final variability limit and assurance level for the control period also would not be known until after the control period. However, because the proposed rule provides that the variability limit would always be at least 21 percent, the sources in a state would be able to rely for planning purposes on the knowledge that the assurance level would always be at least 121 percent of the state's emissions budget for the control period. Advance knowledge of the minimum possible amount of the assurance level can be useful to sources, because one way a source can be confident that it will never incur the 3-for-1 allowance surrender ratio owed for emissions exceeding its state's assurance level is to plan its operations so as to never allow its own emissions to exceed its own share of the state's assurance level for the control period. Knowing that the variability limit would always be at least 21 percent would provide sources with values they could use for such planning purposes.

The EPA believes that 21 percent is a reasonable value to use as the fixed variability limit for the 2023 and 2024 control periods and as the minimum variability limit for the control periods in 2025 and later years. To determine appropriate variability limits for the trading programs established in CSAPR, the EPA analyzed historical state-level heat input variability over the period from 2000 through 2010 as a proxy for emissions variability, assuming constant emissions rates. *See* 76 FR 48265. Based on that analysis, the variability limits for ozone season NO_X in both CSAPR and the CSAPR Update were set at 21 percent of each state's budget, and these variability limits for the NO_X ozone season trading programs were then codified in 40 CFR 97.510 and 40 CFR 97.810, along with the respective state budgets. For the Revised CSAPR Update, the EPA performed an updated variability analysis for the twelve states being moved into the Group 3 trading program in that rulemaking, evaluating historical state-level heat input variability over the period from 2000 through 2019. The updated analysis again resulted in a variability estimate of 21 percent. The EPA also considered shorter time periods for the updated analysis and found that the resulting variability estimates were not especially sensitive to the particular time period analyzed.[266] A further updated analysis for this rulemaking again results in a variability estimate of 21 percent for most states, and although the historical analysis indicates higher percentages for the two states with the smallest total heat input figures in this analysis—Delaware and New Jersey—the EPA does not consider it appropriate to raise the variability limit percentage beyond 21 percent for all other states based on the analytic results for these states, where small absolute heat input figures have resulted in larger variability percentages.[267] Based on the consistent conclusions of these multiple analyses, the EPA proposes to continue using 21 percent as the fixed variability limit percentage for the 2023 and 2024 control periods and as the minimum value in the revised approach for establishing variability limits for the control periods in 2025 and later years.

The EPA requests comment on the proposed rule to set variability limits for the 2023 and 2024 control periods as 21 percent of the respective revised state emissions budgets, consistent with the methodology used to determine the variability limits for these control periods set in the Revised CSAPR Update. In addition, the EPA requests comment on whether to set higher variability limits for Delaware and New Jersey for 2023 and 2024 based on the results of the most recent variability analysis. The EPA also requests comment on the proposed rule to establish a revised methodology for setting variability limits for all states for control periods in 2025 and later years, as discussed in this section.

6. Annual Recalibration of Allowance Bank

As discussed in Section VII.B.1.b of this proposed rule, in this rulemaking, the EPA is proposing two revisions to the Group 3 trading program designed to better maintain the control stringency selected in the final rule in this rulemaking. The first proposed revision, discussed Section VII.B.4 of this proposed rule, is to adopt a dynamic budget-setting methodology that would allow state emissions budgets in future years to reflect more accurate information about the composition and utilization of the EGU fleet. The second, complementary, proposed revision is to recalibrate the bank of unused allowances each control period in order to prevent allowance surpluses in individual control periods from accumulating and adversely impacting the ability of the trading program in future control periods to maintain the selected control stringency identified in the rulemaking as necessary to address states' good neighbor obligations with respect to the 2015 ozone NAAQS.

The EPA proposes to begin the bank recalibration process starting with the 2024 control period, after the compliance process for the 2023 control period for all current and newly added states in the Group 3 trading program

[266] For details on the original variability analysis for 26 states over the 2000–2010 period, including a description of the methodology, see the Power Sector Variability Final Rule TSD from the CSAPR (EPA–HQ–OAR–2009–0491–4454). For the updated variability analysis for twelve states for the 2000–2019 period, *see* the Excel file ''Historical Variability in Heat Input 2000 to 2019.xls.'' Both documents are available in the docket for this proposal.

[267] *See* the Excel document, ''OS Heat Input Variability 2000 to 2021.xls'' for updated data, application of the CSAPR variability methodology, and results applied to heat input for 2000 through 2021 for all states and for the region collectively.

has been completed. The recalibration process for each control period would be carried out on or shortly after August 1 of that control period, two months after the compliance deadline for the previous control period, making the proposed date of the first recalibration August 1, 2024. The recalibrations could not take place significantly earlier than August 1 each year because compliance for the previous control period would not be completed until after June 1. However, because data on the amounts of allowances held are publicly available and the total quantity of allowances needed for compliance for the previous control period would be known shortly after the end of that control period, sources and other market participants would be able to ascertain with reasonable accuracy shortly after the end of each control period what degree of recalibration to expect for the next control period, even if the recalibration would not actually be carried out until the following August.

Before undertaking a recalibration process each control period, the EPA would first determine whether the total amount of all banked Group 3 allowances from previous control periods held in all facility accounts and general accounts in the Allowance Management System accounts exceeds the target bank amount. (For this purpose, no distinction would be made between banked Group 3 allowances issued from the state emissions budgets for previous control periods and banked Group 3 allowances issued through the conversion of previously banked Group 2 allowances.) If the total amount of banked Group 3 allowances does not exceed the target bank amount, the EPA would not carry out any recalibration for that control period. If the total amount of unused allowances does exceed the target bank amount, the EPA would determine for each account with holdings of banked Group 3 allowances the account-specific recalibrated amount of allowances, computed as the target bank amount multiplied by the account's total holdings of banked Group 3 allowances and divided by the total amount of banked Group 3 allowances in all accounts, rounded up to the nearest allowance. Finally, the EPA would deduct from each account any banked Group 3 allowances exceeding the account's recalibrated amount of banked allowances.

As the target bank amount used in the recalibration process for each control period, the EPA proposes to use an amount determined as 10.5 percent of the sum of the state emissions budgets for the control period, or half of the sum of the states' proposed minimum variability limits. The EPA has two reasons for proposing this amount. First, in the transition from CSAPR to the CSAPR Update, where the EPA set a target bank amount 1.5 times the sum of the variability limits, and in the transition from the CSAPR Update to the Revised CSAPR Update, where the EPA set a target bank amount of 1.0 times the sum of the variability limits, in each case the initial bank proved larger than necessary, as total emissions of all sources in the program were less than the budgets. Second, an analysis of year-to-year variability of heat input for the region covered by this proposed rule suggests that the regional heat input for an individual year can be expected to vary by up to 10.5 percent above or below the central trend with 95% confidence. This variability analysis is an application to the entire region of the variability analysis EPA has performed for individual states to establish the variability limit of 21 percent for the states in the trading program.[268] When the analysis is performed at the regional level, the data show less year-to-year variation than when the analysis is performed at the individual state level. Within the trading program structure, it is logical to use variability analyzed at the level of individual states to set the variability limits, which apply at the level of individual states, while using variability analyzed at the level of the overall region to set a target level for a bank, which will apply at the level of the overall program.

The annual bank recalibrations will help maintain the control stringency determined to be necessary to address states' good neighbor obligations for the 2015 ozone NAAQS. Moreover, the proposed recalibrations are less complex than alternative approaches would be. For example, the NO_X Budget Trading Program established in the NO_X SIP Call also contained provisions designed to prevent excessive accumulations of banked allowances on program stringency, but those provisions—under the name ''progressive flow control''—introduced uncertainty as to whether banked allowances would be usable to offset one ton of emissions or less than one ton of emissions in the current control period. The EPA considers the recalibration mechanism proposed here to be simpler with less associated uncertainty.

Finally, the EPA observes that the proposed recalibration mechanism is entirely consistent with the Agency's existing authority under 40 CFR 97.1006(c)(6) to ''terminate or limit the use and duration'' of any Group 3 allowance ''to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.'' The Administrator proposes to determine that the recalibrations are both necessary and appropriate to ensure that the control stringency selected in this rulemaking is maintained and states' good neighbor obligations with respect to the 2015 ozone NAAQS are addressed.

The EPA requests comment on the proposed bank recalibration provisions and the proposed use of a target bank amount computed as 10.5 percent times the sum of the state emissions budgets for each control period.

7. Unit-Specific Backstop Daily Emissions Rates

While the identified EGU emissions reductions in Section VI of this proposed rule are incentivized and secured primarily through the corresponding seasonal state emissions budgets (expressed as a seasonal tonnage limit for all covered EGUs within a state's borders) described earlier, the EPA is also incorporating backstop daily emissions rates of 0.14 lb/mmBtu for coal-fired steam units serving generators with nameplate capacity greater than or equal to 100 MW in covered states. The backstop emissions rates will first apply in 2024 for coal-fired steam units with existing SCR controls, and in 2027 for coal-fired steam units currently without SCR controls. For a unit that exceeds its applicable backstop daily emissions rate on any day, all emissions on that day exceeding the emissions that would have occurred at the backstop daily emissions rate will be subject to a 3-for-1 allowance surrender ratio instead of the normal 1-for-1 allowance surrender ratio. See Appendix A of the Ozone Transport Policy Proposed Rule TSD for a list of coal-fired steam units serving generators larger than or equal to 100 MW in covered states for which the identified backstop emissions rate would apply starting in either 2024 or 2027.

The EGU NO_X Mitigation Strategies Proposed Rule TSD describes the methodology for deriving the 0.14 lb/mmBtu daily rate limit in more detail. The methodology is summarized as follows. First, consistent with

[268] See the Power Sector Variability Final Rule TSD from CSAPR, available at *https://www.epa.gov/csapr/power-sector-variability-final-rule-tsd for a description of the methodology*. Also see the Excel document ''OS Heat Input—Variability 2000 to 2021.xls'' for updated data, application of the CSAPR variability methodology, and results applied to heat input for 2000 through 2021 for all states and for the region collectively.

stakeholders' focus on providing daily assurance of control operation, EPA determined that daily (as opposed to hourly or monthly) was an appropriate time metric for backstop emissions rate limits instituted to ensure operation of controls on high ozone days. The EPA derived the 0.14 lb/mmBtu daily rate limit by determining the particular level of a daily rate that would be comparable in stringency to the 0.08 lb/mmBtu seasonal emissions rate that the Agency has identified as reflecting SCR optimization at existing units.[269] The EPA first conducted an empirical exercise using reported daily emissions rate data from existing, SCR-controlled coal units that were emitting at or below 0.08 lb/mmBtu on a seasonal average basis. Recognizing that this seasonal rate reflects the average across a unit's range of varying daily rates reflecting different operation conditions, including some occasions when the SCR control may not be operating or may not be fully optimized, the EPA identified the upper end of the daily emissions rate range for these units. When the EPA examined the daily emissions rate pattern for these units considered to be optimizing their SCRs on a seasonal basis, the EPA observed that over 95 percent of the time, their daily rates were below 0.14 lb/mmBtu. In addition, for these units, less than 1 percent of their seasonal emissions would exceed this daily rate limit.

The EPA conducted this analysis to be consistent with the methodology developed in the 2014 1-hr SO_2 attainment area guidance for identifying ''comparably stringent'' emissions rates over varying time-periods.[270] Appendix C of that guidance describes a series of steps that involve: (1) Compiling emissions data to reflect a distribution of emissions rates with various averaging times, (2) determining the 99th percentile of the average emissions values compiled in the previous step, and then (3) applying ''adjustment factors'' or ratios of the 99th percentile values to emissions rates to convert them (usually from a short-term rate to a longer-term rate). In this case, the EPA applied the methodology in reverse to convert a longer-term limit (the seasonal rate of 0.08 lb/mmBtu which was assumed to be equal to a 30-day rate of 0.08 lb/mmBtu) to a comparably stringent short-term limit (a daily rate of 0.14 lb/mmBtu). The EPA requests comment on the proposed incorporation of a backstop daily emissions rate element into the Group 3 trading program and on the proposed methodology for determining the daily emissions rate of 0.14 lb/mmBtu.

In addition, the EPA requests comment on application of the backstop daily emissions rates in the event that an affected unit finds it more economic to retire shortly after the start of the 2027 ozone season in lieu of investing in new NO_X post-combustion control technology. This proposed rule's state emissions budgets would require emissions reductions starting in 2026 commensurate with SCR retrofits at these units regardless of when these unit-level backstop rates are subsequently imposed. The EPA recognizes that such retrofits in practice may be less environmentally efficient compared to imminent retirement that would potentially yield lower cumulative emissions of NO_X and multiple other pollutants over time. The EPA also recognizes that several coal-fired EGUs have been considering retirement by 2028 under compliance pathways available under Clean Water Act effluent guidelines[271] and the coal combustion residuals rule under the Resource Conservation and Recovery Act.[272] 2028 also represents the end of the second planning period under the Regional Haze program, and thus is a significant year in states' planning of strategies to make reasonable progress towards natural visibility at Class I areas.[273] To facilitate a potentially economic and environmentally superior unit-level compliance response across these programs that nonetheless maintains the NO_X reductions required by the state budgets from 2026 forward in this proposed rule, the EPA is requesting comment on potentially deferring the application of the backstop daily rate for large coal EGUs that submit written attestation to the EPA that they make an enforceable commitment to retire by no later than the end of calendar year 2028. EPA anticipates that units failing to retire contrary to their attestation would become subject to the backstop emissions rate in the 2029 ozone season, and would likely be subject to other appropriate enforcement proposed rule under the Clean Air Act or other relevant authorities.

8. Unit-Specific Emissions Limitations Contingent on Assurance Level Exceedances

As emphasized by the D.C. Circuit in its decision invalidating CAIR, under the CAA's good neighbor provision, emissions ''within the State'' that contribute significantly to nonattainment or interfere with maintenance of a NAAQS in another state must be prohibited. *North Carolina* v. *EPA,* 531 F.3d 896, 906–908 (D.C. Cir. 2008). The CAIR trading programs contained no provisions limiting the degree to which a state could rely on net purchased allowances as a substitute for making in-state emissions reductions, an omission which the court found was inconsistent with the requirements of the good neighbor provision. *Id.* In response to that holding, the EPA established the CSAPR trading programs' assurance provisions to ensure that, in the context of a flexible trading program, the emissions reductions required under the good neighbor provision in fact will take place within the state. The EPA believes the assurance provisions have generally been successful in achieving that objective, as evidenced by the fact that since the assurance provisions took effect in 2017, out of the nearly 300 instances where a given state's compliance with the assurance provisions of a given CSAPR trading program for a given control period has been assessed, a state's collective emissions have exceeded the applicable assurance level only four times.

Unfortunately, the EPA also recognizes that the assurance provisions' very good historical compliance record is not good enough. The four past exceedances all occurred under the Group 2 trading program: Sources in Mississippi collectively exceeded their applicable assurance levels in the 2019 and 2020 control periods, and sources in Missouri collectively exceeded their applicable assurance levels in the 2020 and 2021 control periods.[274] Both of the

[269] *See* page 24 of ''Guidance for 1-hour SO_2 Nonattainment Area SIP Submission'' at *https://www.epa.gov/sites/default/files/2016-06/documents/20140423guidance_nonattainment_sip.pdf.* ''A limit based on the 30-day average of emissions, for example, at a particular level is likely to be a less stringent limit than a 1-hour limit at the same level 1 since the control level needed to meet a 1-hour limit every hour is likely to be greater than the control level needed to achieve the same limit on a 30-day average basis.''

[270] *See* Guidance for 1-Hour SO_2 Nonattainment Area SIP Submissions available at *https://www.epa.gov/sites/default/files/2016-06/documents/20140423guidance_nonattainment_sip.pdf.*

[271] *See* 40 CFR 423.11(w).

[272] *See* 40 CFR 257.103(b).

[273] *See* 40 CFR 51.308(f).

[274] Information on the assurance level exceedances in the 2019 and 2020 control periods is available in the final notices concerning EPA's administration of the assurance provisions for those control periods. 85 FR 53364 (August 28, 2020); 86 FR 52674 (September 22, 2021). The EPA will publish an analogous final notice for the 2021 control period by October 1, 2022, and will also publish a preliminary notice by August 1, 2022. At this time, information on the relevant Missouri assurance level for the 2021 control period is available at 40 CFR 97.806(c)(2) and 97.810 and preliminary data on Missouri units' emissions of

exceedances by Missouri sources could easily have been avoided if the owner and operator of several SCR-equipped, coal-fired steam units had not chosen to idle the units' controls and rely instead on net out-of-state purchased allowances. The exceedances were large, and ample quantities of allowances to cover the resulting 3-for-1 allowance surrender requirements were purchased in advance, suggesting that the assurance level exceedances may have been anticipated as a possibility. In the case of the Mississippi exceedances, the exceedances were smaller, operational variability (manifesting as increased heat input) appears to have been a material contributing factor, and the EPA has not concluded that the owners and operators anticipated the exceedances. However, an additional contributing factor was the fact that several large, gas-fired steam units without SCR controls emitted NO_X at average rates much higher than the average emissions rates the same units had achieved in previous control periods. In short, while the Missouri exceedances appear far more significant, EPA's analysis indicates that all four past exceedances could have been avoided if the units most responsible had achieved emissions rates more comparable to the same units' previous performance. In EPA's view, the operation of the Missouri units in particular—although not prohibited by the current regulatory requirements—cannot be reconciled with the statutory requirements of the good neighbor provision. The fact that such operation is not prohibited by the current regulations therefore indicates a deficiency in the current regulatory requirements.

To correct the deficiency in the regulatory requirements, the EPA proposes in this rulemaking to revise the Group 3 trading program regulations to establish an additional emissions limitation to more effectively deter avoidable assurance level exceedances. Because the pollutant involved is ozone season NO_X and the particular sources for which deterrence is most needed are located in states that are proposed to transition soon from the Group 2 trading program to the Group 3 trading program, the EPA is proposing to promulgate the strengthening provisions as revisions to the Group 3 trading program regulations rather than the Group 2 trading program regulations.[275]

The two current emissions-related compliance requirements in the Group 3 trading program regulations are both structured in the form of requirements to hold allowances. The first requirement applies at the source level: Specifically, at the compliance deadline after each control period, the owners and operators of each source covered by the program must surrender a quantity of allowances that is determined based on the emissions from the units at the source during the control period. The second requirement applies at the designated representative level (which typically is the owner or operator level): If the state's sources collectively emit in excess of the state's assurance level, the owners and operators of each set of sources determined to have contributed to the exceedance must surrender an additional quantity of allowances. As long as a source's owners and operators comply with these two allowance surrender requirements (and meet certain other requirements not related to the amounts of the sources' emissions), they are in compliance with the program.

In light of the operation of the Missouri sources, the EPA is doubtful that strengthening the assurance provisions by increasing allowance surrender requirements at the unit, source, or designated representative level would create a sufficient deterrent. Accordingly, the EPA is proposing instead to add a new, unit-level emissions limitation structured as a prohibition to emit NO_X in excess of a defined amount. A violation of the prohibition would not trigger additional allowance surrender requirements beyond the surrender requirements that would otherwise apply, but would trigger the possible application of the CAA's enforcement authorities. Because the purpose of the new unit-level emissions limitation would be to deter conduct causing exceedances of a state's assurance level, the EPA proposes to condition applicability of the new limitation on (1) the occurrence of an exceedance of the state's assurance level for the control period, and (2) the apportionment of at least some of the responsibility for the assurance level exceedance to the set of units represented by the unit's designated representative. Apportionment of responsibility for the assurance level exceedance would be carried out according to the existing assurance provision procedures and would therefore depend on the designated representative's shares of both the state's total emissions for the control period and the state's assurance level for the control period. The new emissions limitation would be in addition to, not in lieu of, the other requirements of the Group 3 trading program. This point would be made explicit by relabeling the source-level allowance holding requirement, currently called the ''emissions limitation,'' as the ''primary emissions limitation'' and labeling the new unit-level requirement as the ''secondary emissions limitation.'' (The regulations label the designated representative-level requirement as ''compliance with the . . . assurance provisions.'')

The EPA proposes to define the unit-level secondary emissions limitation by formula to reflect the amount of additional NO_X emissions caused by the unit's deviation from a benchmark seasonal average NO_X emissions rate during the control period, where the benchmark seasonal average NO_X emissions rate for the unit would be based on emissions rates the unit has achieved in the past plus a 25 percent margin. The EPA also proposes to use a floor for past performance of 0.08 lb/mmBtu (yielding 0.10 lb/mmBtu when the 25 percent margin is added), exclude control periods where the unit operated in less than 10 percent of the hours (in order to avoid data that might be unrepresentative), and screen out instances where the amount of additional emissions caused by the poor performance is less than 50 tons. Specifically:

- The EPA proposes to define a unit's secondary emissions limitation for a control period, in tons of NO_X, as the sum of 50 tons plus the product of (1) the unit's benchmark seasonal average emissions rate times (2) the unit's actual heat input for the control period, except that if the unit operated during less than 10 percent of the hours in the control period, no secondary emissions limitation would be defined for the unit for that control period.
- The EPA proposes to calculate the benchmark seasonal average NO_X

NO_X during the 2021 ozone season are available at *ampd.epa.gov.*

[275] The EPA believes that the occurrence of avoidable assurance level exceedances under the Group 2 trading program, combined with the express statutory directive that good neighbor obligations must be addressed ''within the state,'' and through ''prohibition,'' would also provide a sufficient legal basis for the Agency to promulgate the same revisions to the assurance provisions for all the other CSAPR trading programs. The EPA is not proposing to do so at this time because the Agency has seen no reason to expect exceedances of the assurance levels under any of the other CSAPR trading programs by any of the states that will remain subject to the respective trading programs after this rulemaking, except possibly by Missouri under the CSAPR NO_X Annual Trading Program. The EPA expects that reductions in Missouri's seasonal NO_X emissions sufficient to comply with the proposed provisions of the revised Group 3 trading program, including the secondary emissions limitations, would also prevent exceedances of Missouri's currently applicable assurance level for annual NO_X emissions.

emissions rate for a unit for this purpose, in lb NO_X/mmBtu, as the higher of (1) 0.10 lb/mmBtu or (2) 125 percent of the unit's lowest seasonal average NO_X emissions rate in a previous control period under the CSAPR NO_X Ozone Season Group 1, Group 2, or Group 3 Trading Program, excluding any control periods where the unit operated for less than 10 percent of the hours in the ozone season.[276]

Table VII.B.8–1 shows the secondary emissions limitations that the proposed formula would have produced and which units would have exceeded those limitations if the limitations and formula had been in effect for the Group 2 trading program in 2019, 2020, and 2021 when assurance level exceedances occurred in Mississippi and Missouri. The EPA believes that in each case the formula functions in a reasonable manner, and the units identified as exceeding their respective secondary emissions limitations are sources for which an enforcement deterrent under CAA sections 113 and 304 would have been appropriate to compel better control of NO_X emissions.

TABLE VII.B.8–1—ILLUSTRATIVE RESULTS OF APPLYING PROPOSED SECONDARY EMISSIONS LIMITATION IN PREVIOUS INSTANCES OF ASSURANCE LEVEL EXCEEDANCES

Owner/operator	Unit	Benchmark NO_X emissions rate (lb/mmBtu)	Actual NO_X emissions rate (lb/mmBtu)	Secondary emissions limitation (tons)	Actual NO_X emissions (tons)	Exceedance (tons)
Mississippi—2019						
Miss. Power	Watson 4	0.137	0.176	458	524	66
Miss. Power	Watson 5	0.215	0.349	1,247	1,943	696
Mississippi—2020						
Entergy Miss.	Andrus 1	0.224	0.289	1,219	1,508	289
Miss. Power	Watson 5	0.215	0.286	1,086	1,381	295
Missouri—2020						
Assoc. Elec. Coop.	New Madrid 1	0.135	0.670	961	4,524	3,563
Assoc. Elec. Coop.	New Madrid 2	0.131	0.497	866	3,108	2,242
Assoc. Elec. Coop.	Thomas Hill 1	0.123	0.526	374	1,384	1,010
Assoc. Elec. Coop.	Thomas Hill 2	0.122	0.537	548	2,187	1,639
Assoc. Elec. Coop.	Thomas Hill 3	0.104	0.195	780	1,374	594
Missouri—2021						
Assoc. Elec. Coop.	New Madrid 1	0.135	0.652	353	1,466	1,113
Assoc. Elec. Coop.	New Madrid 2	0.131	0.611	1,054	4,700	3,646
Assoc. Elec. Coop.	Thomas Hill 1	0.123	0.146	421	440	19
Assoc. Elec. Coop.	Thomas Hill 2	0.122	0.400	600	1,801	1,201

For further illustrations of the application of the proposed formula and secondary emissions limitation to other units in the states proposed to be subject to the expanded Group 3 trading program in the control periods from 2016 through 2021, see the spreadsheet ''Illustrative Calculations Using Proposed Secondary Emissions Limitation Formula'', available in the docket. The EPA notes that, with the exception of the units listed in Table VII.B.8–1, no unit shown in the spreadsheet as having emissions exceeding the illustrative secondary emissions limitation calculated for the unit would have violated the proposed prohibition because no violation would occur in the absence of an exceedance of the assurance level and apportionment of responsibility for a share of the exceedance to the unit under the assurance provisions.

The EPA requests comment on the proposal to establish a secondary emissions limitation for the Group 3 trading program as described in this section. The EPA specifically requests comment on the proposed form of the secondary emissions limitation, the proposed formula for computing each unit's secondary emissions limitation, and the proposed values for the screening parameters used in the calculations.

9. Unit-Level Allowance Allocation and Recordation Procedures

In the Revised CSAPR Update, the EPA established default procedures for allocating CSAPR NO_X Ozone Season Group 3 allowances (''Group 3 allowances'') in amounts equal to each state emissions budget for each control period among the sources in the state for use in complying with the Group 3 trading program. The EPA also provided states with several options to submit SIP revisions which, if approved, would result in the replacement of EPA's allowance allocations with state-determined allowance allocations for the 2022 control period and beyond. The current regulations (*i.e.,* before this proposed rule) provide that EPA's allocations and allocation procedures apply for the 2021 control period and, by default, for subsequent control periods unless and until a state provides state-determined allowance allocations under an approved SIP revision.

The current default allocation process for the Group 3 trading program established in the Revised CSAPR Update involves three main steps. First, a portion of each state emissions budget for each control period is reserved for potential allocation to units that are subject to allowance holding requirements and that would not otherwise receive allowance allocations in the overall allocation process. Under the current Group 3 trading programs, the reserved allowances are made available generally (but not exclusively[277]) to ''new'' units—which for purposes of the Revised CSAPR Update means units commencing commercial operation on or after January 1, 2019—through a ''new unit set-aside'' established for qualifying units in each state and, if areas of Indian country exist within the state's borders, a separate ''Indian country new unit set-

[276] In proposing a formulation for a benchmark rate for the specific regulatory purpose of defining a secondary emissions limitation under the Group 3 trading program, the EPA is not expressing a view that the same formulation of a benchmark rate would be suitable for any other regulatory purpose.

[277] The units qualifying for allocations from a new unit set-aside may include not only units that have recently started operating but also units that previously received, but are no longer eligible to receive, allocations from the unreserved portion of the budget as ''existing'' units.

aside'' for qualifying units in such Indian country. Second, in advance of each control period, the unreserved portion of the state budget is allocated among the state's eligible ''existing'' units—which for purposes of the Revised CSAPR Update generally means units that commenced commercial operation before January 1, 2019—and the allocations are recorded in the respective sources' compliance accounts. Finally, after the control period but before the compliance deadline by which sources must hold allowances to cover their emissions for the control period, allowances from the reserved portions of the budget are allocated to qualifying units, any remaining reserved allowances not allocated to qualifying units are allocated among the state's existing units, and the allocations are recorded in the respective sources' compliance accounts.

In this rulemaking, the EPA would retain the overall three-step allocation process summarized above but is proposing revisions to each step to better address units in Indian country and to better coordinate the unit-level allocation process with the proposed dynamic budget-setting process discussed in Section VII.B.4 of this proposed rule. Like the allocation process established in CSAPR, the CSAPR Update, and the Revised CSAPR Update, the revised process proposed in this rulemaking would be designed to provide default allowance allocations to all units that are subject to allowance holding requirements, including, for the first time under any CSAPR trading program, an existing EGU in Indian country not covered by a state's CAA implementation planning authority. The proposed revisions to the three steps are discussed in Sections VII.B.4.a, VII.B.4.b, and VII.B.4.c of this proposed rule, respectively.

Echoing the approach to unit-level allocations followed in CSAPR, the CSAPR Update, and the Revised CSAPR Update, in this rulemaking, EPA is again proposing to provide states with several options to submit SIP revisions which, if approved, would result in the replacement of EPA's default allocations with state-determined allocations for subsequent control periods. Specifically, the proposed regulations would provide that EPA's allocations and allocation procedures will apply for the 2023 control period and, by default, for subsequent control periods unless and until a state provides state-determined allocations under an approved SIP revision. The options to submit SIP revisions that would accomplish this purpose are discussed in Section VII.D of this document. Similarly, for a covered area of Indian country not subject to a state's CAA implementation planning authority, a tribe could elect to work with the EPA under the Tribal Authority Rule to develop a full or partial tribal implementation plan under which the tribe would determine allowance allocations that would replace EPA's default allocations for subsequent control periods.

a. Set-Asides of Portions of State Emissions Budgets for New Units

As the first step in the default allocation process that the EPA has applied under CSAPR, the CSAPR Update, and the Revised CSAPR Update for any control period where a state does not employ an alternative allocation process pursuant to an approved SIP revision, EPA has reserved a portion of the state's emissions budget for potential allocation to units that are subject to allowance holding requirements and that would not otherwise receive allowance allocations in the overall allocation process. Consistent with the budget-setting approach in those rulemakings, where the state emissions budgets for all future control periods were determined in the initial rulemakings, the amounts of the reserved portions of the budgets were also determined in the initial rulemakings.[278]

The units for which portions of the budgets were reserved in set-asides have fallen into two main categories: First, units for which the data needed to determine allowance allocations does not exist at the time when the allocations for other units were being determined—*i.e.,* ''new'' units[279]—and second, units that would be left out if a state chooses to replace EPA's default allocations with state-determined allocations—*i.e.,* any units in Indian country not covered by a state's CAA implementation planning authority. Because there were no existing units in what the EPA understood to be Indian country for purposes of CSAPR, the CSAPR Update, and the Revised CSAPR Update, potential units in Indian country were considered to be a subcategory of ''new'' units, and the two types of set-asides that have been created are ''new unit set-asides'' and ''Indian country new unit set-asides.'' The principal difference between these two types of set-asides under the regulations for all of the CSAPR trading programs has been that a state can take over administration of the allowances allocated to a new unit set-aside from the EPA through an approved SIP revision but cannot take over administration of the allowances allocated to an Indian country new unit set-aside.

In this rulemaking, the EPA is proposing several revisions affecting the establishment of set-asides. The first proposed revision, which is largely unrelated to the other aspects of this rulemaking, would update the regulations for the Group 3 trading program[280] to reflect the D.C. Circuit's holding in *ODEQ* v. *EPA* that the relevant states have initial CAA implementation planning authority in non-reservation areas of Indian country until displaced by a demonstration of tribal jurisdiction over such an area.[281] Consistent with this holding, EPA is proposing to revise language in the Group 3 trading program regulations that, for purposes of allocating allowances from a given state's emissions budget, currently distinguishes between (1) the set of units within the state's borders that are not in Indian country and (2) the set of units within the state's borders that are in Indian country. As revised, the provisions would distinguish between (1) the set of units within the state's borders that are not in Indian country or are in areas of Indian country covered by the state's CAA implementation planning authority and (2) the set of units within the state's borders that are in areas of Indian country not covered by the state's CAA implementation planning authority. The revised language would more accurately distinguish which units are, or are not, covered by a state's CAA implementation planning authority, which is the underlying purpose for which the term ''Indian country'' is currently used in the allowance allocation provisions. The effect of the proposed revision would be that any

[278] Under the current regulations for each of the CSAPR trading programs, when a unit that has received allocations as an ''existing'' unit ceases operation, after a specified number of control periods the unit loses the allocations, which are then allocated to the state's new unit set-asides for subsequent control periods.

[279] A unit that has received allocations as an ''existing'' unit, then loses its allocations because of non-operation, and then later resumes operation is treated as a type of ''new'' unit for allocations purposes.

[280] As further discussed in Section VII.B.12 of this proposed rule, the EPA is also proposing to make this revision to the regulations for the other CSAPR trading programs in addition to the Group 3 trading program.

[281] For additional discussion of the *ODEQ* v. *EPA* decision and other issues related to the CAA implementation planning authority of states, tribes, and the EPA in various areas of Indian country, *see* Section IV.C.2 of this proposed rule.

units located in areas of ''Indian country'' as defined in 18 U.S.C. 1151 that are covered by a state's CAA implementation planning authority would be treated for allowance allocation purposes in the same manner as units in areas of the state that are not Indian country, consistent with the *ODEQ* holding.[282]

The remaining proposed revisions, which are interrelated, concern the types of set-asides that in the context of this proposal will best accomplish the goal of ensuring the availability of allocations to units that are subject to allowance holding requirements and that would not otherwise receive allowance allocations. One proposed revision to the types of set-asides addresses allocations to existing units in Indian country. The revised geographic scope of the Group 3 trading program under this proposal would for the first time include an existing EGU in Indian country not covered by a state's CAA implementation planning authority—the Bonanza coal-fired unit in the Uintah and Ouray Reservation within Utah's borders. In order to provide an option for Utah (or a similarly situated state in the future) to replace EPA's default allowance allocations to most existing units with state-determined allocations through a SIP revision while continuing to ensure the availability of a default allocation to the Bonanza unit (or similarly situated units in the future), the EPA proposes to revise the Group 3 trading program regulations to provide for ''Indian country existing unit set-asides.'' Specifically, for each state and for each control period where the inventory of units used to compute the state's emissions budget includes one or more existing units [283] in an area of Indian country not covered by the state's CAA implementation planning authority, the EPA would reserve a portion of the state's emissions budget in an Indian country existing unit set-aside for the unit or units. The amount of each Indian country existing unit set-aside would equal the sum of the default allocations that the units covered by the set-aside would receive if the allocations to all existing units within the state's borders were computed according to EPA's default allocation procedure (which is discussed in Section VII.B.9.b of this proposed rule). Immediately after determining the amount of a state's emissions budget for a control period (and after reserving a portion for potential allocation to new units, as discussed below), the EPA would first determine the default allocations for all existing units within the state's borders, then allocate the appropriate quantity of allowances to the Indian country existing unit set-aside, then allocate the allowances from the set-aside to the covered units in Indian country, and finally record the allocations in the sources' compliance accounts at the same time as the allocations to other sources not in Indian country. The existence of the Indian country existing unit set-aside thus would have no substantive effect unless and until the relevant state chose to replace EPA's default allowance allocations through a SIP revision, in which case the state would have the ability to establish state-determined allocations for the units subject to the state's CAA implementation planning authority while the EPA would continue to administer the Indian country existing unit set-aside for the units in Indian country not covered by the state's CAA implementation planning authority.[284] The EPA believes the proposal to establish Indian country existing unit set-asides would accomplish the objective of allowing states to control allowance allocations to units covered by their CAA implementation planning authority while providing equitable allocations to units in Indian country not covered by such authority.

The remaining revisions to the types of set-asides address the set-asides used to ensure availability of allowance allocations to *new* units in light of the division of the budget for *existing* units into a reserved portion for existing units in Indian country and an unreserved portion for other existing units. Under the current Group 3 trading program regulations, allowances for new units are provided from separate new unit set-asides and Indian country new unit set-asides. The EPA proposes to combine these two types of set-asides starting with the 2023 control period by eliminating the Indian country new unit set-asides and expanding eligibility for allocations from the new unit set-asides to include units anywhere within the relevant states' borders. However, as with the Indian country new unit set-asides under the current regulations, the EPA would continue to administer the new unit set-asides in the event a state chose to replace EPA's default allocations to existing units with state-determined allocations, thereby ensuring the availability of allocations to any new units not covered by a state's CAA implementation planning authority.

The reason for the proposed revisions to the new unit set-asides and Indian country new unit set-asides is to avoid unnecessary and potentially inequitable changes to the degree to which individual existing units contribute to, or benefit from, the new unit set-asides. Under the current regulations, the allowances used to establish these set-asides are reserved from each state emissions budget before determination of the allocations from the unreserved portion of the budget to existing units, so that certain existing units—generally those receiving the largest allocations—contribute to creation of the set-asides through roughly proportional reductions in their allocations. Later, if any allowances in a set-aside are not allocated to qualifying new units, the remaining allowances are reallocated to the existing units in proportion to their initial allocations from the unreserved portion of the budget, so that certain existing units—again, generally those receiving the largest allocations—benefit from the reallocations in rough proportion to their previous contributions.[285] The EPA believes maintaining this symmetry, where the same existing units—whether in Indian country or not—both contribute to and potentially benefit from the set-asides, is a reasonable policy objective, and doing so requires that the EPA continue to administer the new unit set-asides in the event a state chooses to replace EPA's default allocations to existing units with state-determined allocations, because otherwise the EPA would be unable to ensure that the units in Indian country would receive an appropriate

[282] The EPA notes that the units that would be treated for allocation purposes in the same manner as units not in Indian country would include units in any areas of Indian country subject to a state's CAA implementation planning authority, whether those are non-reservation areas (consistent with *ODEQ*) or reservation areas (such as areas of Indian country within Oklahoma's borders covered by the EPA's October 1, 2020 approval of Oklahoma's request under SAFETEA, as discussed in Section IV.C.2 of this proposed rule).

[283] In coordination with the dynamic budgeting process discussed in Section VII.B.4 of this proposed rule, each unit included in the unit inventory used to determine a state's emissions budget for a given control period in 2025 or a later year would be considered an ''existing'' unit for that control period for purposes of the determination of unit-level allowance allocations. In other words, there would no longer be a single fixed date that would divide ''existing'' from ''new'' units.

[284] As noted in Section VII.D, of this proposed rule a tribe could elect to work with EPA under the Tribal Authority Rule to develop a full or partial tribal implementation plan under which the tribe would determine allowance allocations for units in the relevant area of Indian country that would replace EPA's default allocations for subsequent control periods.

[285] Allowances from an Indian country new unit set-aside that are not allocated to qualifying new units are first transferred to the state's new unit set-aside, and if the allowances are still not allocated to qualifying new units, the allowances are then reallocated to the state's existing units.

share of any reallocated allowances.[286] Since the principal difference between the new unit set-asides and the Indian country new unit set-asides under the current regulations is that the EPA continues to administer the Indian country new unit set-asides in the event a state chooses to replace EPA's default allocations with state-determined allocations, if under the revised regulations the EPA would need to continue to administer the new unit set-asides, then there would no longer be any reason to establish separate Indian country new unit set-asides.

With respect to the total amounts of allowances that would be set aside for potential allocation to new units from the emissions budgets for each state, for the control periods in 2023 and 2024 (but not for subsequent control periods, as discussed below), EPA proposes to establish total set-aside amounts equal to the projected amounts of emissions from any planned units in the state for the control period, plus an additional 2% of the state emissions budget to address any unknown new units. For example, if planned units in a state are projected to emit 3% of the state's NO_X ozone season emissions budget, then the new unit set-aside for the state would be set at 5 percent, which is the sum of the minimum 2% set-aside plus an additional 3 percent for planned units. This is the same approach previously used to establish the amounts of new unit set-asides in CSAPR, the CSAPR Update, and the Revised CSAPR Update for all the CSAPR trading programs. *See, e.g.,* 76 FR 48292 (August 8, 2011). As under the Revised CSAPR Update, EPA proposes to make an exception for New York for the 2023 and 2024 control periods, establishing a total new unit set-aside amount for each control period of 5 percent of the state's emissions budget, with no additional consideration for planned units, because this approach is consistent with New York's preferences as reflected in an approved SIP addressing allowance allocations for the Group 2 trading program. Because the amounts of the state emissions budgets for the 2023 and 2024 control periods would be determined in the rulemaking, the amounts of the new unit set-asides for these control periods would also be determined in the rulemaking. The proposed amounts are shown in Tables VII.B.9.a-1 and VII.B.9.a-2 of this proposed rule.

TABLE VII.B.9.a–1—PROPOSED CSAPR NO_X OZONE SEASON GROUP 3 NEW UNIT SET-ASIDE (NUSA) AMOUNTS FOR THE 2023 CONTROL PERIOD [a]

State	Emissions budgets (tons)	New unit set-aside amount (percent)	New unit set-aside amount (tons)
Alabama	6,364	3	191
Arkansas	8,889	2	178
Delaware	384	14	54
Illinois	7,364	5	368
Indiana	11,151	2	223
Kentucky	11,640	2	233
Louisiana	9,312	2	186
Maryland	1,187	2	24
Michigan	10,718	4	429
Minnesota	3,921	2	78
Mississippi	5,024	2	100
Missouri	11,857	2	237
Nevada	2,280	6	137
New Jersey	799	2	16
New York	3,763	5	188
Ohio	8,369	5	418
Oklahoma	10,265	2	205
Pennsylvania	8,855	3	266
Tennessee	4,234	2	85
Texas	38,284	2	766
Utah	14,981	3	449
Virginia	3,090	5	155
West Virginia	12,478	2	250
Wisconsin	5,963	2	119
Wyoming	9,125	3	274

Table Notes:

[a] In the event a final rule in this rulemaking becomes effective after May 1, 2023, the emissions budgets for the 2023 control period would be adjusted under the rule's proposed transitional provisions to ensure the new budgets would apply only after the rule's effective date, even though the revised Group 3 trading program would be implemented for most sources as of the start of the 2023 ozone season on May 1, 2023. The 2023 budget amounts shown in Table VII.B.9.a–1 do not reflect these possible adjustments. The transitional provisions are discussed in Section VII.B.11 of this proposed rule.

[286] If units in Indian country were unable to share in the benefits of reallocation of allowances from the new unit set-asides, it would be possible to achieve a different form of symmetry by simultaneously exempting the units in Indian country from the obligation to share in the contribution of allowances to the new unit set-asides. However, some stakeholders might view this alternative as potentially inequitable because existing units in Indian country would then make no contributions toward the new unit set-aside while other existing units would still be required to do so.

TABLE VII.B.9.a–2—PROPOSED CSAPR NO_X OZONE SEASON GROUP 3 NEW UNIT SET-ASIDE (NUSA) AMOUNTS FOR THE 2024 CONTROL PERIOD

State	Emissions budgets (tons)	New unit set-aside amount (percent)	New unit set-aside amount (tons)
Alabama	6,306	3	189
Arkansas	8,889	2	178
Delaware	434	14	61
Illinois	7,463	5	373
Indiana	9,391	2	188
Kentucky	11,640	2	233
Louisiana	9,312	2	186
Maryland	1,187	2	24
Michigan	10,718	4	429
Minnesota	3,921	2	78
Mississippi	4,400	2	88
Missouri	11,857	2	237
Nevada	2,372	6	142
New Jersey	799	2	16
New York	3,763	5	188
Ohio	8,369	5	418
Oklahoma	9,573	2	191
Pennsylvania	8,855	3	266
Tennessee	4,234	2	85
Texas	38,284	2	766
Utah	15,146	3	454
Virginia	2,814	5	141
West Virginia	12,478	2	250
Wisconsin	5,057	2	101
Wyoming	8,573	3	257

For control periods in 2025 and later years, the EPA proposes to allocate a total of 2% of each state emissions budget to a new unit set-aside, with no additional amount for planned new units. The amounts of the set-asides for each state and control period would be computed when the emissions budgets for the control period are established, by May 1 of the year before the year of the control period. The procedure for determining the amounts of the set-asides based on the amounts of the state emissions budgets would be codified in the Group 3 trading program regulations and would reflect the same percentage of the emissions budget for all states.

The purpose of the proposed change to the procedure for establishing the amounts of the set-asides is to coordinate with the dynamic budget-setting process that would also become effective as of the 2025 control period. As discussed in Section VII.B.4 of this proposed rule, under the dynamic budget-setting process, each state's budget for each control period would be computed using fleet composition information and the total ozone season heat input reported by all affected units in the state for the latest control period before the budget-setting computations, which would be 2 years before the control period for which the budgets are being determined. (For example, 2025 emissions budgets would be based on 2023 fleet composition and heat input data.) Moreover, as discussed in Section VII.B.9.b of this proposed rule, all units whose heat input was used in the budget computations for a given control period would be eligible to receive allocations as ''existing'' units in that control period. Consequently, by the 2025 control period, all or almost all units that commence commercial operation before issuance of a final rule in this rulemaking would be considered ''existing'' units for purposes of budget-setting and allocations, and units commencing commercial operation after issuance of a final rule generally would be considered ''existing'' units for all but their first two full control periods of operation (and possibly a preceding partial control period). Given that new units would not be relying on the new unit set-asides as a permanent source of allowances, as is the case for ''new'' units under the other CSAPR trading programs, the EPA believes smaller set-asides would be sufficient.

The EPA requests comment on the proposals to establish Indian country existing unit set-asides, eliminate Indian country new unit set-asides, and expand eligibility for allocations from new unit set-asides to include units in Indian country for control periods in 2023 and later years. In the alternative, the EPA requests comment on establishing emissions budgets (and assurance levels and new unit set-asides) for the Uintah and Ouray Reservation separate from the emissions budgets (and assurance levels, new unit set-asides, and Indian country new unit set-asides) established for the remaining lands within Utah's borders, and otherwise retaining the structure of prior CSAPR trading programs' approach to allocations to new units in Indian country (*i.e.,* keeping the Indian country new unit set-asides, and not expanding eligibility for allocations from the new unit set-asides). The EPA also requests comment on the proposed new unit set-aside amounts for the 2023 and 2024 control periods, the proposed procedure for establishing the new unit set-aside amounts for the control periods in 2025 and later years, and the proposed procedure for establishing the Indian country existing unit set-aside amounts for the control periods in 2023 and later years.

b. Allocations to Existing Units, Including Units That Cease Operation

In conjunction with the new and revised state emissions budgets for the Group 3 trading program proposed in this rulemaking, the EPA is necessarily proposing new unit-level allocations of Group 3 allowances to existing units.[287]

[287] The proposed revisions to the procedures for computing unit-level allowance allocations in this rulemaking apply only to the Group 3 trading

The procedure that the EPA proposes to employ to compute the unit-level allocations is very similar but not identical to the procedure used to compute unit-level allocations for units subject to the Group 3 trading program in the Revised CSAPR Update. The steps of the proposed procedure for determining allocations from each state emissions budget for each control period, are described in detail in the Unit-Level Allowance Allocations Proposed Rule TSD. The steps are summarized later, with changes from the procedure followed in the Revised CSAPR Update noted.

In the first step, the EPA would identify the list of units eligible to receive allocations for the control period, which would be the same set of units whose heat input was used in computing the state's emissions budget for the control period (except any units that are included in the budgets as ''new'' units, which would receive allocations from the new unit set-asides instead). The unit inventories used to compute emissions budgets for the 2023 and 2024 control periods would be determined in the rulemaking in the same manner as in the Revised CSAPR Update. The unit inventories used to compute emissions budgets and unit-level allocations for control periods in 2025 and later years would be determined in the year before the control period in question based on the latest reported emissions and operational data, which is an extension of the methodology used in the Revised CSAPR Update to reflect more recent data (for example, the unit inventories used to compute 2025 budgets and allocations would reflect reported data for the 2023 control period). The procedures for updating the unit inventories for 2023 and 2024 and for 2025 and beyond are discussed in Section VII.B.4 of this proposed rule, and the criteria that the EPA has applied to determine whether a unit's scheduled retirement is sufficiently certain to serve as a basis for adjusting emissions budgets and unit-level allocations are discussed in Section VI.B and in the Ozone Transport Policy Analysis Proposed Rule TSD. With regard to the use of the inventories from the budget-setting procedure in setting unit-level allocations, in the Revised CSAPR Update, the inventories used to establish the budgets were generally also used to compute unit-level allocations, except that units that commenced construction after January 1, 2019, were not treated as eligible to receive allocations as existing units and instead received allocations from the new unit set-asides. Under this rulemaking, any unit whose heat input is used to set a state's emissions budget for a given control period would also be eligible to receive allocations as an existing unit for that control period.

The EPA notes that this proposal to base the list of eligible units on the list of units that reported heat input in the control period 2 years earlier than the control period for which allocations are being determined would represent a revision to the current regulations concerning the treatment of allocations to retired units. Under the current regulations, units that cease operations for 2 consecutive control periods continue to receive allocations as existing units for 3 additional years (that is, a total of 5 years) before the allowances they would otherwise have received are reallocated to the new unit set-aside for the state. Under the proposal in this rulemaking, units that cease operation would receive allocations for only two full control periods of non-operation. While the EPA has in prior transport rulemakings noted a qualitative concern that ceasing allowance allocations prematurely could distort the economic incentives of EGUs to continue operating when retirement is more economical, the EPA believes current market conditions are such that a continuation of allowance allocations to retiring units likely has no more than a de minimis effect on the consideration of an EGU whether to retire or not.

In the second step of the procedure for determining allocations to existing units, the EPA would compile a database containing for each eligible unit the unit's historical heat input and total NO_X emissions data for the five most recent ozone seasons. For each unit, the EPA would compute an average heat input value based on the three highest non-zero heat input values over the 5-year period, or as the average of all the non-zero values in the period if there are fewer than three non-zero values. For each unit, the EPA would also determine the maximum total NO_X emissions value over the 5-year period. These procedures are nearly identical to the procedures used in the Revised CSAPR Update, with two exceptions. First, instead of using only the data available at the time of the rulemaking, for each control period the EPA would use data from the most recent five control periods for which data had been reported. (For example, for the 2025 control period, the EPA would use data for the 2019–2023 control periods.) Second, to simplify the data compilation process, the EPA would use only a five-year period for NO_X mass emissions, in contrast to the 8-year period used in the Revised CSAPR Update for NO_X mass emissions.

In the third step of the procedure for determining allocations to existing units in each state, the EPA would allocate the available allowances for that state among the state's eligible units in proportion to the share each unit's average heat input value represents of the total of the average heat input values for all the state's eligible units, but not more than the unit's maximum total NO_X value. If the allocations to one or more units are curtailed because of the units' maximum total NO_X values, the EPA would iterate the calculation procedure as needed to allocate the remaining allowances, excluding from each successive iteration any units whose allocations have already reached their maximum total NO_X values. This calculation procedure is identical to the calculation procedure used in the Revised CSAPR Update (as well as the CSAPR Update and CSAPR).

The unit-level allocations for the 2023 and the 2024 control periods would be determined in the rulemaking based on the emissions budgets for those control periods also determined in the rulemaking and would be recorded 30 days after the effective date of the final rule (in order to provide time to execute the proposed recall of 2023 and 2024 Group 2 allowances, as discussed in Section VII.B.11.c of this proposed rule). This proposed recordation schedule represents a revision to the recordation schedule currently in the Group 3 trading program regulations which calls for allocations of 2023 and 2024 Group 3 allowances to existing units to be recorded on July 1, 2022. The EPA notes that for the three states with approved SIP revisions establishing their own methodologies for allocating Group 2 allowances—Alabama, Indiana, and New York—EPA proposes to follow those methodologies to the extent possible in developing the allocations of Group 3 allowances for the 2023 and 2024 control periods. For the amounts of the proposed allocations to existing units for the 2023 and 2024 control periods, see the ''Unit-Level Allowance Allocations Proposed Rule TSD'' in the docket.

The unit-level allocations for each control period in 2025 or a later year would be computed immediately following the determination of the emissions budgets for the control period. The EPA would perform the

program. In this rulemaking, the EPA is not proposing changes to or reopening the methodology for computing the amounts of allowances allocated to any unit under any other CSAPR trading program.

computations and issue a notice of data availability concerning the preliminary unit-level allocations for each control period by March 1 of the year before the control period. Objections to the data and preliminary computations could be submitted for 30 days, and the EPA would make any appropriate revisions and issue another notice of data availability by May 1 of the year before the control period. The EPA would then record the allocations by July 1 of the year before the control period. This proposed recordation schedule—which is necessitated by the fact that the amounts of the unit-level allocations to be recorded would not be known until the year before the control period, as just discussed—represents a revision to the recordation schedule currently in the Group 3 trading program regulations which calls for allocations of Group 3 allowances to existing units for control periods in 2025 and later years to be recorded on July 1 of the third year before the year of the control period. The EPA does not propose to follow any state-specific methodologies as part of the procedures for determining default unit-level allocations of Group 3 allowances for control periods in 2025 or later years, but any state wishing to use a procedure different than EPA's default allocations procedure could do so by obtaining approval of a SIP revision, as discussed in Section VII.D of this proposed rule.

In the case of any states making state-determined allocations under approved SIP revisions, the allocations would have to be submitted to EPA by June 1 of the year before the control period and the EPA would record the allocations by July 1 of the year before the control period. The proposed submission deadline would represent a revision of the current deadline of June 1 of the year 3 years before the control period, and the proposed recordation deadline would represent a revision of the current deadline of July 1 of the year 3 years before the control period. The purpose of revising the submission deadline is to provide each state for which the EPA has approved a SIP revision authorizing state-determined allowance allocations a period of time in which to apply the state's preferred allocation methodology to the state's trading budget for the appropriate control period. Because the state trading budgets under the Group 3 trading program as revised would not be known until May 1 of the year before each control period, states could not determine unit-level allocations of the budgets using their own methodologies significantly before June 1 of the year before the control period. Submission by June 1 would allow the allowance allocations to the units in the state to be recorded by July 1 of the year before the control period, simultaneously with the recordation of allocations to units in states where the EPA determines the allocations.

As an exception to all of the recordation deadlines that would otherwise apply, the EPA proposes to not record any allocations of Group 3 allowances in a source's compliance account unless that source has complied with the requirements to surrender previously allocated 2023–2024 Group 2 allowances. The surrender requirements are necessary to maintain the previously established levels of stringency of the Group 2 trading program for the states and sources that remain subject to that program under this final rule. The EPA finds that it is reasonable to condition the recordation of Group 3 allowances on compliance with the surrender requirements because the condition will spur compliance and will not impose an inappropriate burden on sources. The EPA considers establishment of this condition, which will facilitate the continued functioning of the Group 2 trading program, to be an appropriate exercise of the Agency's authority under CAA section 301 (42 U.S.C. 7601) to prescribe such regulations as are necessary to carry out its functions under the Act.

The EPA requests comment on the proposed revisions to the procedures for allocating allowances to existing units under the Group 3 trading program, the deadlines for recording the allocations, and the deadlines for submission of state-determined allowance allocations to the EPA.

c. Allocations From Portions of State Emissions Budgets Set Aside for New Units

As promulgated in the Revised CSAPR Update, the Group 3 trading program regulations provide for the EPA to allocate allowances from each new unit set-aside and Indian country new unit set-aside after the end of the control period at issue. The regulations call for the EPA to allocate allowances to any eligible ''new'' units in the state in proportion to their respective emissions during the control period, up to the amounts of those emissions if the relevant set-aside contains sufficient allowances, and not exceeding those emissions. An eligible new unit for purposes of allocations from a set-aside for a given control period is generally any unit in the relevant area that reported emissions subject to allowance surrender requirements during the control period and that was not eligible to receive an allowance allocation as an ''existing'' unit for the control period. Any allowances remaining in an Indian country new unit set-aside after the allocations to new units are transferred to the new unit set-aside for the state for potential allocation to new units in non-Indian country areas of the state, and any allowances remaining in a new unit set-aside after the allocations to new units are reallocated to the existing units in the state in proportion to those units' previous allocations for the control period as existing units. The EPA issues a notice of data availability concerning the proposed allocations by March 1 following the control period, provides an opportunity for submission of objections, and issues a final notice of data availability and record the allocations by May 1 following the control period, one month before the June 1 compliance deadline.

In this rulemaking, as discussed in Section VII.B.9.a of this document, the EPA is proposing to eliminate Indian country new unit set-asides after the 2022 control period and to expand eligibility for allocations from each state's new unit set-aside for a control period in 2023 or a later year to include units in Indian country within the state's borders, regardless of whether the area of Indian country is covered by the state's CAA implementation planning authority. The reasons for these proposed revisions are discussed in Section VII.B.9.a of this proposed rule. The EPA is not proposing any substantive revisions to the current Group 3 trading program provisions governing the procedures for allocating allowances from a state's new unit set-aside for a control period to the eligible units within the state's borders.[288]

This EPA notes that the proposed revisions to other provisions of the Group 3 trading program regulations discussed elsewhere in this document will reduce the portions of the state emissions budgets that are allocated through the new unit set-asides. Specifically, because the new unit set-asides will no longer receive any additional allowances when units retire, for control periods in 2025 and later years the amounts of allowances in the new unit set-asides will always be 2 percent of the respective state emissions budgets for the respective control periods. This reduction in the size of the

[288] As discussed in Section X of this proposed rule, the EPA is proposing to relocate some of the regulatory provisions relating to administration of the new unit set-asides and is also proposing to remove certain provisions that would be made obsolete by proposed revisions to other provisions of the Group 3 trading program regulations.

new unit set-asides is appropriate given that the number of consecutive control periods for which any particular unit is likely to receive allocations from a state's new unit set-aside will be reduced to two or three before the unit becomes eligible to receive allocations from the unreserved portion of the state's emissions budget. This approach contrasts with the approach under the other CSAPR trading programs where a new unit never becomes eligible to receive allocations from the unreserved portion of the emissions budget and where the new unit set-aside therefore needs to grow to accommodate an ever-increasing share of the state's total emissions.

The EPA also notes that, as discussed in Sections VII.D.2 and VII.D.3 of this proposed rule, in the event that a state chooses to replace EPA's default allowance allocations under the Group 3 trading program with state-determined allocations through a SIP revision, the EPA will continue to administer the portion of each state emissions budget reserved in a new unit set-aside in order to ensure the availability of allowance allocations to new units in any areas of Indian country within the state not covered by the state's CAA implementation planning authority.

d. Incorrectly Allocated Allowances

The Group 3 trading program regulations as promulgated in the Revised CSAPR Update include provisions addressing incorrectly allocated allowances. With regard to any allowances that were incorrectly allocated and are subsequently recovered, the current provisions generally call for the recovered allowances to be reallocated to other units in the relevant state (or Indian country within the borders of the state) through the process for allocating allowances from the new unit set-aside (or Indian country new unit set-aside) for the state. If the procedures for allocating allowances from the set-asides have already been carried out for the control period for which the recovered allowances were issued, the allowances would be allocated through the set-asides for subsequent control periods.

The EPA continues to view the current provisions for disposition of recovered allowances as reasonable in the case of any allowances that are recovered before the deadline for recording allocations of allowances from the new unit set-aside for the control period for which the recovered allowances were issued. However, in the case of any allowances that are recovered after that deadline, adding the recovered allowances to the new unit set-aside for a subsequent control period, as provided in the current regulations, would be inconsistent with the proposed trading program enhancements discussed elsewhere in this document, where the amounts of allowances provided in the state emissions budgets for each control period are designed to reflect the most current available information on fleet composition and utilization and where the quantities of banked allowances available for use in each control period are recalibrated for consistency with the state emissions budgets. The EPA therefore proposes that, starting with allowances allocated for the 2024 control period, any incorrectly allocated allowances that are recovered after the deadline for allocating allowances from the new unit set-aside for that control period (*i.e.,* May 1 of the year following the control period) would be transferred to a surrender account instead of being reallocated to other units in the state.

The EPA requests comment on the proposed revision to the provisions for disposition of incorrectly allocated allowances that are recovered after the deadline for allocating allowances from the new unit set-asides for the control periods for which the recovered allowances were issued.

10. Other Trading Program Provisions

This section discusses how certain existing provisions of the Group 3 trading program regulations would apply to sources that become subject to the program as a result of a final rule in this rulemaking as well as certain proposed changes to reporting requirements associated with the proposed backstop daily NO_X emissions rates for coal-fired units.

a. Designated Representative Requirements

As noted in Section VII.B.1.a of this document, a core design element of all the CSAPR trading programs is the requirement that each source must have a designated representative who is authorized to represent all of the source's owners and operators and is responsible for certifying the accuracy of the source's reports to the EPA and overseeing the source's Allowance Management System account. The necessary authorization of a designated representative is certified to the EPA in a certificate of representation. The EPA is not proposing any change to the Group 3 trading program's designated representative provisions in this rulemaking.

The existing designated representative provisions in the Group 3 trading program regulations already provide that EPA will interpret references to the Group 2 trading program in certain documents—including a certificate of representation as well as a notice of delegation to an agent or an application for a general account—as if the documents referenced the Group 3 trading program instead of the Group 2 trading program. For these reasons, sources that currently participate in the Group 2 trading program and that transition to the Group 3 trading program because of a final rule in this rulemaking will not need to submit any new forms as part of the transition, because previously submitted forms will be valid for purposes of the Group 3 trading program.

Designated representatives for sources that are newly affected under the Group 3 trading program and that are not currently affected under the Group 2 trading program would need to submit new or updated certificates of representation. If the source is also affected under other CSAPR trading programs or the Acid Rain Program, the source's designated representative for all of the programs must be the same individual. The EPA will not record any Group 3 allowances allocated to a source in the source's compliance account until the source has a properly authorized designated representative.

b. Monitoring and Reporting Requirements

The Group 3 trading program requires monitoring and reporting of emissions and heat input data in accordance with the provisions of 40 CFR part 75. In this rulemaking, the EPA is not proposing any change to these provisions of the Group 3 trading program except with respect to the monitor certification deadline for certain units. The EPA is also not proposing any changes to the monitoring requirements in 40 CFR part 75 for units subject to such requirements. However, because of the proposed geographic expansion of the Group 3 trading program, certain units that were not previously subject to monitoring requirements under 40 CFR part 75 would become subject to such requirements. Also, the EPA is proposing certain additional recordkeeping and reporting requirements that would be met using some of the data that are already collected by the required monitoring systems.[289]

[289] The EPA is not proposing to amend the existing provisions of the Group 3 trading program regulations that govern whether units covered by the program must record and report required data on a year-round basis or may elect to record and

Continued

Under 40 CFR part 75, a unit has several options for monitoring and reporting, including the use of continuous emissions monitoring systems (CEMS), excepted monitoring methodologies for qualifying gas- or oil-fired units that rely in part on fuel-flow metering in combination with CEMS-based or testing-based NO_X emissions rate data, low-mass emissions monitoring for certain non-coal-fired, low emitting units, and alternative monitoring systems approved by the Administrator through a petition process. In addition, sources can submit petitions to the Administrator for alternatives to individual monitoring, recordkeeping, and reporting requirements specified in 40 CFR part 75. Each CEMS must undergo rigorous initial certification testing and periodic quality assurance testing thereafter, including the use of relative accuracy test audits and 24-hour calibrations. In addition, when a monitoring system is not operating properly, standard substitute data procedures are applied to produce a conservative estimate of emissions for the period involved. Further, 40 CFR part 75 requires electronic submission of quarterly emissions reports to the Administrator, in a format prescribed by the Administrator. The reports would contain all of the data required concerning ozone season NO_X emissions.

For units exhausting to common stacks, 40 CFR part 75 includes options that often allow monitoring to be conducted at the common stack on a combined basis for all the units as an alternative to installing separate monitoring systems for the individual units in the ductwork leading to the common stack. The units then keep records and report hourly and cumulative NO_X mass emissions and in many cases heat input data on a combined basis for all units exhausting to the common stack. With respect to heat input data, but not NO_X mass emissions data, most such units are also required to record and report hourly and cumulative data on an individual-unit basis, and where necessary they typically compute the necessary unit-level hourly heat input values by apportioning the combined hourly heat input values for the common stack in proportion to the individual units' recorded hourly output of electricity or steam. *See generally* 40 CFR 75.72.

In this rulemaking, the proposed provisions governing default unit-level allowance allocations, backstop daily NO_X emissions rates for certain coal-fired units, and secondary emissions limitations for units contributing to assurance level exceedances would all require the use of unit-level reported data on NO_X mass emissions (or unit-level NO_X emissions rates computed in part based on unit-level reported data on NO_X mass emissions). To facilitate the implementation of these proposed provisions, the EPA is proposing to require all units covered by the Group 3 trading program exhausting to common stacks to record and report unit-level hourly and cumulative NO_X mass emissions data starting with the 2024 control period. To obtain the necessary unit-level hourly mass emissions values, the EPA proposes to allow the units to apportion hourly mass emissions values determined at the common stack in proportion to the individual units' recorded hourly heat input. The proposed apportionment procedure would be very similar to the apportionment procedure that most such units already apply to compute reported unit-level heat input data. Because the additional required data values would be obtained through apportionment, implementation of the proposed additional recordkeeping and reporting requirements would necessitate a one-time update to the units' data acquisition and handling systems but would not require any changes to the monitoring systems already needed to meet other requirements under 40 CFR part 75. In most cases, the EPA expects that the reported values computed through these apportionment procedures would reasonably approximate the values that could be obtained through installation and operation of separate monitoring systems for the individual units, because the units exhausting to the common stack would be expected to have similar NO_X emissions rates. However, the EPA also recognizes that at some plants, unit-level values determined through apportionment based on electricity or steam output could overstate the reported NO_X mass emissions for some units and correspondingly understate the reported NO_X mass emissions for other units. While the EPA has not at this time identified any reason to expect such potential overstatement and understatement to cause the proposed requirements in this rule to be less stringent overall, the Agency requests comment on whether units in particular situations should be required to obtain the necessary hourly mass emissions values through installation and operation of monitoring systems at the individual-unit level.[290]

In addition, to implement the proposed backstop daily NO_X emissions rates during the ozone season for certain coal-fired units, the EPA is proposing to require additional recordkeeping and reporting requirements for these units. Specifically, starting in 2024 for coal-fired units with existing SCR controls serving generators larger than 100 MW, and starting in 2027 for other coal-fired units serving generators larger than 100 MW (except circulating fluidized bed units), the units would be required to record and report total daily NO_X emissions and total daily heat input, daily average NO_X emissions rate, and daily NO_X emissions exceeding the applicable backstop daily NO_X emissions rates. The units would also be required to record and report cumulative NO_X emissions exceeding the backstop daily NO_X emissions rates for the ozone season. These data would be used to determine the allowance surrender requirements related to the backstop daily NO_X emissions rates. As with the additional recordkeeping and reporting requirements discussed above for units exhausting to common stacks, implementation of the additional recordkeeping and reporting requirements for coal-fired units would necessitate a one-time update to the units' data acquisition and handling systems but would not require any changes to the monitoring systems already needed to meet other requirements under 40 CFR part 75.

In states whose sources currently participate in the Group 3 trading program, as well as states whose sources participate in the Group 2 trading program and would transition to the

report required data on an ozone season-only basis. *See* 40 CFR 97.1034(d)(1); *see also* 40 CFR 75.74(a)–(b). Thus, for units that are required or elect to report other data on a year-round basis, the proposed additional recordkeeping and reporting requirements would also apply year-round, while for units that are allowed and elect to report other data on an ozone season-only basis, the proposed additional requirements would also apply for the ozone season only.

[290] For example, as noted in Section VII.B.7 of this proposed rule, there are currently five plants in the states covered by this proposal where SCR-equipped coal-fired units and non-SCR-equipped coal-fired units exhaust to common stacks. If the owners and operators of these plants choose to report apportioned NO_X mass emissions data in preference to installing and operating separate monitoring systems, the likely effect would be to overstate reported NO_X mass emissions for the SCR-equipped units and correspondingly understate reported NO_X mass emissions for the non-SCR equipped units. This would make compliance with the proposed backstop daily NO_X emissions rate more challenging for the SCR-equipped units. If the EPA does not require the owners and operators to install and operate separate monitoring systems for the individual units in a final rule in this rulemaking, the owners and operators would still have the option to do so if they believed it would be to their benefit.

Group 3 trading program under this proposal, units that are not subject to the proposed backstop daily NO_X emissions rates would not need to make any changes to their current monitoring and reporting as a result of the transition. The sources in states currently in the Group 2 trading program would be required to begin monitoring and reporting of NO_X emissions and operational data for purposes of the Group 3 trading program as of May 1, 2023, the start of the 2023 control period.

In states whose sources do not currently participate in the Group 2 trading program, any sources that currently report ozone season NO_X mass emissions according to 40 CFR part 75 to comply with SIP requirements and that are not subject to the proposed backstop daily NO_X emissions rates similarly would not need to make any changes to their current monitoring and reporting as a result of the transition. Other sources in these states that currently report SO_2 and NO_X emissions data according to 40 CFR part 75 under other CSAPR trading programs or the Acid Rain Program would not need to certify new monitoring systems for purposes of the Group 3 trading program but would need to update their monitoring plans and possibly update the software in their data acquisition and handling systems to compute certain additional values from the measurements that are already being recorded. All the sources in these states that already have monitoring systems certified under 40 CFR part 75 would be required to begin monitoring and reporting of NO_X emissions and operational data for purposes of the Group 3 trading program as of the later of May 1, 2023, or the effective date of the final rule.[291]

Finally, any sources that meet the applicability criteria of the Group 3 trading program and that do not currently report NO_X emissions data to the EPA under 40 CFR part 75 would need to certify new monitoring systems in accordance with part 75 before they would be required to monitor and report emissions for purposes of the Group 3 trading program. The units the EPA has been able to identify as potentially affected under this proposal that may need to certify new monitoring systems are listed in Table VII.B.3–1 (along with some other units that are potentially affected under this proposal and that already have certified monitoring systems). Because each of the listed units commenced commercial operation more than 180 days before the date when a final rule in this rulemaking would become effective, under the current Group 3 trading program regulations (*i.e.,* without the revisions proposed in this section), each unit's monitor certification deadline would generally be the effective date of the final rule. To ensure that the final rule does not impose monitor installation and certification requirements on these units before the effective date of the final rule, the EPA is proposing to revise the Group 3 trading program's monitor certification deadline provisions to establish a 180-day window for certification of the new monitoring systems after the effective date of a final rule in this rulemaking for units that do not already have monitoring systems certified under 40 CFR part 75, similar to the 180-day window already provided to units commencing commercial operation after (or less than 180 days before) the final rule's effective date. The 180th day for units in this situation would likely fall after the end of the 2023 ozone season, with the result that the certification deadline would be extended until May 1, 2024, the first day of the 2024 ozone season. Because the program's allowance holding requirements apply to a given unit only after that unit's monitor certification deadline, the units in this situation consequently would become subject to allowance holding requirements as of the 2024 ozone season rather than the 2023 ozone season.[292]

The EPA requests comment on the proposed revisions to the recordkeeping and reporting provisions in 40 CFR part 75 and the proposed establishment of a 180-day window for certification of new monitoring systems after the effective date of a final rule in this rulemaking for units that do not already have monitoring systems certified under 40 CFR part 75. As discussed above, with respect to units exhausting to common stacks, the EPA also requests comment on whether units in particular situations should be required to obtain hourly NO_X mass emissions values through installation and operation of monitoring systems at the individual-unit level instead of being allowed to obtain values for individual units through apportionment of the combined values for the units exhausting to the common stack.

11. Transitional Provisions

This section discusses several provisions that the EPA proposes to implement in order to address the transition of sources into the Group 3 trading program as revised. The purposes of the proposed transitional provisions are generally the same as the purposes of the analogous transitional provisions promulgated in the Revised CSAPR Update: First, accounting for the possibility that the effective date of a final rule in this rulemaking will fall after the starting date of the first affected ozone season (which in this case is, May 1, 2023); second, establishing an appropriately-sized initial allowance bank through the conversion of previously banked allowances; and third, preserving the intended stringency of the Group 2 trading program for the sources that will continue to be subject to that program.[293] However, the sources that would be participants in the revised Group 3 trading program under this proposal are transitioning from several different starting points—with some sources already in the Group 3 trading

[291] For units that currently report under 40 CFR part 75 only for annual programs and that use the optional low mass emissions methodology in 40 CFR 75.19, an additional consideration could arise. Specifically, eligibility to use the low mass emissions methodology for reporting ozone season NO_X mass emissions is restricted to units demonstrating that they have not exceeded or will not exceed a maximum of 50 tons of NO_X per ozone season. In theory, some units that would be eligible to use the low mass emissions methodology for purposes of annual programs only might lose that eligibility because of the 50-ton ozone season cap (which does not apply to units reporting for annual programs only). Based on the emissions reports submitted for the 2018–2020 control periods under the Acid Rain Program and the CSAPR annual programs, none of the existing units that currently report under 40 CFR part 75 for annual programs only and that would be added to the Group 3 trading program under the proposal are presently in this theoretical situation.

[292] Table VII.B.3–1 of this proposed rule lists 22 existing units in Delaware, Nevada, Utah, and Wyoming that appear to meet the Group 3 trading program's general applicability criteria and that do not already report NO_X emissions data to the EPA under 40 CFR part 75 pursuant to any other existing regulatory requirements. As noted in Section VII.B.3 of this proposed rule, six of the 22 listed units have reported that they may retire before the 2023 ozone season, and the possibility exists that up to nine of the remaining listed units could qualify for an exemption from the Group 3 trading program available to certain cogeneration units. EPA therefore projects that the revision to the monitor certification deadline proposed in this section, and the related delay in allowance holding requirements from 2023 to 2024, could apply to between seven and 22 units, with the total estimated 2021 ozone season NO_X emissions for all such units ranging between 250 and 450 tons. During the period before allowance holding requirements apply to the units—*i.e.,* the period from the effective date of a final rule in this rulemaking until the start of the 2024 control period—other requirements of the program would still apply, such as the requirement for submission of a certificate of representation by a designated representative and the requirements related to installation and certification of required monitoring systems.

[293] The EPA is not proposing to create a "safety valve mechanism" in this rulemaking analogous to the safety valve mechanism established under the Revised CSAPR Update.

program under its current regulations, some sources coming from the Group 2 trading program, and some sources not currently participating in any seasonal NO_X trading program. EPA is therefore proposing transitional provisions that differ across the sets of potentially affected sources based on the sources' different starting points.

a. Prorating Emissions Budgets, Assurance Levels, and Unit-Level Allowance Allocations in the Event of an Effective Date After May 1, 2023

While it is EPA's intent for a final rule in this rulemaking to take effect before the start of the Group 3 trading program's 2023 control period on May 1, 2023, it is possible that the final rule's effective date will fall after that date. The EPA proposes to address this contingency by determining the amounts of emissions budgets and unit-level allowance allocations on a full-season basis in the rulemaking and by also including provisions in the revised regulations to prorate the full-season amounts as needed to ensure that no sources become subject to new or more stringent regulatory requirements before the final rule's effective date.[294] Variability limits and assurance levels for 2023 would be computed using the appropriately prorated emissions budgets amounts, and unit-level allocations would also be prorated.[295]

As discussed in Section VII.B.2 of this proposed rule, in the case of states (and Indian country within the states' borders) whose sources do not currently participate in either the Group 2 trading program or the Group 3 trading program—Delaware, Minnesota, Nevada, Utah, and Wyoming—the sources would begin participating in the Group 3 trading program on the later of May 1, 2023, or the final rule's effective date. For these states, in the rulemaking the EPA would compute the full-season emissions budgets that would apply for the entire 2023 control period if the final rule becomes effective no later than May 1, 2023, and is therefore in effect for the entire 153-day control period from May 1, 2023, through September 30, 2023. If the final rule becomes effective after May 1, 2023, the EPA would determine prorated emissions budgets by multiplying each full-season emissions budget by the number of days from the rule's effective date through September 30, 2023, dividing by 153 days, and rounding to the nearest allowance. The prorated variability limits would be computed as 21 percent of the prorated emissions budgets, rounded to the nearest allowance, yielding prorated assurance levels that equal 121 percent of the prorated emissions budgets. To determine unit-level allocation amounts from the prorated emissions budgets, the EPA would determine full-season allocation amounts in the rulemaking and would determine preliminary prorated allocation amounts in the same manner as described for the emissions budgets previously. The preliminary prorated amounts of the largest unit-level allowance allocations for each state would then each be adjusted up or down by one allowance as needed to cause the sum of the final prorated unit-level allowance allocations for the state to equal the state's prorated emissions budget. All calculations required to determine the prorated emissions budgets and variability limits and the unit-level allocations for the 2023 control period would be carried out as soon as possible after the EPA learns the effective date of a final rule in this rulemaking (which is expected to be approximately 60 days after the date of the final rule's publication in the **Federal Register**). The unit-level allocations for both the 2023 and 2024 control periods would be recorded in facilities' compliance accounts approximately 30 days after the final rule's effective date, as discussed in Section VII.B.9.b of this proposed rule.

In the case of states (and Indian country within the states' borders) whose sources currently participate in the Group 3 trading program—Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia—the sources would continue to participate in the Group 3 trading program for the 2023 control period, subject to prorating procedures designed to ensure that the changes in 2023 emissions budgets and assurance levels would not substantively affect the sources' requirements prior to the rule's effective date. For these states, in the rulemaking the EPA would compute the full-season emissions budgets that would apply for the entire 2023 control period if the final rule becomes effective no later than May 1, 2023, but the EPA would not remove from the regulations the full-season emissions budgets for the 2023 control period that were established in the Revised CSAPR Update rulemaking. Instead, the EPA would include both sets of emissions budgets and variability limits in the regulations, along with a provision indicating that the emissions budgets promulgated in the Revised CSAPR Update would apply on a prorated basis for the portion of the 2023 control period before the final rule's effective date and the emissions budgets established in this rulemaking would apply on a prorated basis for the portion of the 2023 control period on and after the final rule's effective date. Under this provision, the EPA would determine a blended emissions budget for each state for the 2023 control period, computed as the sum of the appropriately prorated amounts of the state's current and revised emissions budgets. (For example, if the final rule became effective on the eleventh day of the 153-day 2023 control period, the blended emissions budget would equal the sum of 10/153 times the current emissions budget plus 143/153 times the revised emissions budget, rounded to the nearest allowance.) Blended variability limits for the 2023 control period would be computed as 21% of the blended emissions budgets, yielding blended assurance levels equal to 121 percent of the blended emissions budgets. Unit-level allocations would be determined by applying the allocation procedure described in Section VII.B.9 of this proposed rule to the blended budgets. In the case of states (and Indian country within the states' borders) whose sources currently participate in the Group 2 trading program—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin—the sources would begin to participate in the Group 3 trading program as of May 1, 2023, regardless of the final rule's effective date, as discussed in Section VII.B.2 of this proposed rule, subject to prorating procedures designed to ensure that the transition from the Group 2 trading program to the Group 3 trading program would not substantively affect the sources' requirements prior to the rule's effective date. The prorating procedures for these states would mirror the procedures for the states currently in the Group 3 trading program, except that because no emissions budgets currently appear in the Group 3 trading program regulations for the states that are currently covered by the Group 2 trading program, the EPA would add two sets of emissions budgets for these states to the Group 3 trading program regulations: First, the states' emissions budgets for the 2023 control period that currently appear in the Group 2 trading

[294] As discussed in Sections VII.B.7 and VII.B.8 of this proposed rule, the proposed revisions establishing unit-specific backstop daily emissions rates and, for units contributing to assurance level exceedances, secondary unit-specific emissions limitations, would not take effect until the 2024 control period or later.

[295] The EPA notes that transitional provisions similar to the prorating provisions proposed in this section were finalized and implemented under the Revised CSAPR Update.

program regulations, which would be included in the revised Group 3 trading program regulations to represent the states' emissions budgets for the portion of the 2023 control period before the final rule's effective date, and second, the emissions budgets for the 2023 control period established for the states in this rulemaking, which would be included in the revised Group 3 trading program regulations to represent the state's emissions budgets for the portion of the 2023 control period on and after the final rule's effective date. The procedures for determining blended emissions budgets, variability limits and assurance levels, and unit-level allowance allocations would be the same as for the states currently in the Group 3 trading program. Again, all calculations required to determine the prorated emissions budgets and variability limits and the unit-level allocations for the 2023 control period would be carried out as soon as possible after the EPA learns the effective date of a final rule in this rulemaking (which is expected to be approximately 60 days after the date of the final rule's publication in the **Federal Register**). The unit-level allocations for both the 2023 and 2024 control periods would be recorded in facilities' compliance accounts approximately 30 days after the final rule's effective date, as discussed in Section VII.B.9.b of this proposed rule.

The reason for proposing that sources currently in the Group 2 trading program would begin to participate in the Group 3 trading program on May 1, 2023 even if the final rule's effective date is after May 1, 2023, is that it would serve the public interest and greatly aid in administrative efficiency for most elements of the Group 3 trading program—specifically, all elements of the trading program other than the elements designed to establish more stringent emissions limitations for the sources coming from the Group 2 trading program—to apply to the sources starting on May 1, 2023. This would facilitate implementation of the Group 3 trading program in an orderly manner for the entire 2023 ozone season and reduce compliance burdens and potential confusion. Each of the CSAPR trading programs for ozone season NO_X is designed to be implemented over an entire ozone season. Implementing the transition from the Group 2 trading program to the Group 3 trading program in a manner that required the covered sources to participate in the Group 2 trading program for part of the 2023 ozone season and the Group 3 trading program for the remainder of that ozone season would be complex and burdensome for sources. Attempting to address the issue by splitting the Group 2 and Group 3 requirements for these sources into separate years is not a viable approach, because EPA has no legal basis for releasing the transitioning Group 2 sources from the emissions reduction requirements found to be necessary in the CSAPR Update for a portion of the 2023 ozone season, and EPA similarly has no legal basis for deferring implementation of the 2023 emissions reduction requirements found to be necessary under this rule for the transitioning Group 2 sources until 2024. Moreover, the requirements of the current Group 2 trading program and the revised Group 3 trading program for the 2023 control period are substantively identical as to almost all provisions, such that with respect to those provisions, a source will not need to alter its operations in any manner or face different compliance obligations as a consequence of a transition from the Group 2 trading program to the Group 3 trading program. Thus, the EPA believes that no substantive concerns regarding retroactivity arise from transitioning the sources currently in the Group 2 trading program to the Group 3 trading program starting on May 1, 2023, as long as those aspects of the revised Group 3 trading program for the 2023 control period that *do* meaningfully differ from the analogous aspects of the Group 2 trading program—that is, the relative stringencies of the two trading programs, as reflected in the emissions budgets and associated assurance levels—are applied only as of the effective date of the final rule.

In all respects other than prorating the emissions budgets, variability limits and assurance levels, and unit-level allowance allocations, with respect to the sources currently participating in the Group 2 trading program or the Group 3 trading program, the EPA proposes to implement the revised Group 3 trading program for the 2023 control period in a uniform manner for the entire control period. Thus, emissions would be monitored and reported for the entire 2023 ozone season (*i.e.,* May 1, 2023, through September 30, 2023), and as of the allowance transfer deadline for the 2023 control period (*i.e.,* June 1, 2024) each source would be required to hold in its compliance account vintage-year 2023 Group 3 allowances not less than the source's emissions of NO_X during the entire 2023 ozone season. Any efforts undertaken by one of these sources to reduce its emissions during the portion of the 2023 ozone season before the effective date of the rule would aid the source's compliance by reducing the amount of Group 3 allowances that the source would need to hold in its compliance account as of the allowance transfer deadline, increasing the range of options available to the source for meeting its compliance obligations under the revised Group 3 trading program. In the case of the sources that do not currently participate in the Group 2 trading program or the Group 3 trading program, the EPA similarly proposes to implement the revised Group 3 trading program for the 2023 control period in a uniform manner for the entire control period, except that the 2023 control period for these sources may be shorter than the normal 153-day length.

The EPA requests comment on this approach for implementing the Group 3 trading program in a manner that would apply the substantive increases in stringency of the emissions budgets and assurance levels established under the final rule on and after, but not before, the final rule's effective date.

b. Creation of Additional Group 3 Allowance Bank for 2023 Control Period

In the CSAPR Update, where the EPA established the Group 2 trading program and transitioned over 95% of the sources that had been participating in what is now the CSAPR NO_X Ozone Season Group 1 Trading Program (the ''Group 1 trading program'') to the new program, the EPA determined that it was reasonable to establish an initial bank of allowances for the Group 2 trading program by converting almost all allowances banked under the Group 1 trading program at a conversion ratio determined by a formula. In the Revised CSAPR Update, where EPA established the Group 3 trading program and transitioned approximately 55% of the sources that had been participating in the Group 2 trading program to the new program, the EPA similarly determined that it was reasonable to establish an initial bank of allowances for the Group 3 trading program by converting allowances banked under the Group 2 trading program at a conversion ratio determined by a formula, using a conversion procedure that was modified to leave much of the Group 2 allowance bank available for use by the approximately 45% of sources then in the Group 2 trading program that would remain in that program. Any conversion of banked allowances from a previous trading program for use in a new trading program must ensure that implementation of the new trading program will result in NO_X emissions reductions sufficient to address significant contribution by all states that would be participating in the new trading program, while also providing industry certainty (and obtaining an environmental benefit) through continued recognition of the value of saving allowances through early reductions in emissions. EPA's approach to balancing these concerns in the CSAPR Update through the conversion of banked allowances from the Group 1 trading program to the Group 2 trading program was upheld in *Wisconsin* v. *EPA,* see 938 F.3d at 321.

In the current rulemaking, applying the same balancing principle as in the CSAPR Update and the Revised CSAPR Update, the EPA proposes to carry out a further conversion of allowances banked for control periods before 2023 under the Group 2 trading program into allowances usable in the Group 3 trading program in control periods in 2023 and later years. Because the EPA is proposing to transition over 90% of the remaining sources in the Group 2 trading program to the Group 3 trading program—much closer to the situation in the CSAPR Update than the situation in the Revised CSAPR Update—in this rulemaking EPA proposes to apply a conversion procedure similar to the procedure followed in the CSAPR Update. Under the proposed conversion procedure, in the final rule in this rulemaking the EPA would not set a predetermined conversion ratio but instead would set provisions defining the types of accounts whose holdings of Group 2 allowances would be converted to Group 3 allowances and establishing the target amount of new Group 3 allowances that would be created. The proposed conversion date would be August 1, 2023, which is 2 months after the compliance deadline for the 2022 control period under the Group 2 trading program and ten months before the compliance deadline for the 2023 control period under the Group 3 trading program. The actual conversion ratio would be determined as of the conversion date and would be the ratio of the total amount of Group 2 allowances held in the identified types of accounts prior to the conversion to the total amount of Group 3 allowances being created. Consistent with the approach taken in the CSAPR Update, the EPA proposes to define the types of accounts included in the conversion to include all accounts except the facility accounts of sources in states that would remain in the Group 2 trading program.[296] Thus, the accounts whose holdings of Group 2 allowances would be converted to Group 3 allowances would include (1) the facility accounts of all sources in the states transitioning from the Group 2 trading program to the Group 3 trading program, (2) the facility accounts of all sources in the states already participating in the Group 3 trading program, (3) the facility accounts of all sources in any other states not covered by the Group 2 trading program that happen to hold Group 2 allowances as of the conversion date, and (4) all general accounts (that is, accounts that are not facility accounts, including other accounts controlled by source owners as well as accounts controlled by non-source entities such as allowance brokers). Creating the new Group 3 allowances through conversion of previously banked Group 2 allowances would also help preserve the stringency of the Group 2 trading program for the states that remain covered by that trading program at levels consistent with the stringency found to be appropriate to address those states' good neighbor obligations with respect to the 2008 ozone NAAQS in the CSAPR Update.

With respect to setting the target amount of Group 3 allowances that would be created in the conversion process, the EPA proposes to follow the same approach that was used in the Revised CSAPR Update for creation of the initial Group 3 allowance bank. Specifically, the target amount of Group 3 allowances to be created would be computed as the sum of the variability limits for the 2024 control period[297] established in the final rule for the states being transitioned to the Group 3 trading program from the Group 2 trading program, prorated to reflect the portion of the 2023 control period occurring on and after the effective date of the final rule. Based on the amounts of the proposed state emissions budgets and variability limits, the full-season target amount for the conversion would be 18,517 Group 3 allowances. The quantity of banked Group 2 allowances currently held in accounts other than the facility accounts of sources in Iowa and Kansas exceeding the quantity of allowances likely to be needed for 2021 compliance is approximately 110,000 allowances. If the quantities of banked Group 2 allowances did not change between now and the conversion date, and if there was no prorating adjustment, the conversion ratio would be approximately 5.9-to-1, meaning that one Group 3 allowance would be created for every 5.9 Group 2 allowances deducted in the conversion process.[298]

As noted in Section VII.B.11.a of this proposed rule, it is possible that the effective date of this rule will occur after the start of the 2023 ozone season, and provisions are being proposed to ensure that the increased stringency of this rule's state budgets and state assurance levels (*i.e.,* the sums of the budgets and variability limits) would take effect only after the rule's effective date. Consistent with these other procedures, the EPA is proposing to similarly prorate the bank target amount used in the conversion process. For example, if the effective date of the final rule is the eleventh day of the 153-day 2023 ozone season, the full-season initial bank target amount of 18,517 allowances would be prorated to an initial bank target amount of 17,307 allowances.[299] The EPA notes that prorating the bank amount in this manner would not reduce sources' compliance flexibility for the 2023 ozone season, because the amounts of Group 3 allowances that sources would receive for the portion of the 2023 ozone season before the rule's effective date would be based on the current trading program budgets for the 2023 control period before this rulemaking. The current trading program budgets exceed the sources' collective 2021 emissions by approximately 18,600 tons, indicating potentially surplus allowances roughly equal to the full-season bank conversion target amount of 18,517 allowances. Thus, although the prorating procedure would reduce the amount of Group 3 allowances that would be available to sources in the form of an initial bank, the reduction in the quantity of these allowances would be offset by the quantities of Group 3 allowances that would be allocated in excess of sources' recent historical emissions levels for the portion of the ozone season before the final rule's effective date.

As in the CSAPR Update and the Revised CSAPR Update, EPA's overall objective in establishing the target amount for the allowance conversion would be to achieve a total target amount for the bank at a level high enough to accommodate year-to-year

[296] If the proposed expansion of geographic scope for the Group 3 trading program is unchanged in the final rule, the states whose sources would continue to participate in the Group 2 trading program would be Iowa and Kansas.

[297] Similar to the approach taken in the Revised CSAPR Update, because emissions reductions from some of the emissions controls that EPA has identified as appropriate to use in setting budgets are first reflected in the 2024 state budgets rather than the 2023 state budgets, the EPA is proposing to base the bank target amount on the sum of the states' 2024 variability limits rather than the 2023 variability limits.

[298] By comparison, the analogous conversion ratio under the Revised CSAPR Update was 8-to-1.

[299] $18{,}517 \times (153 - 10) \div 153 = 17{,}307$.

variability in operations and emissions, as reflected in states' variability limits, but not high enough to allow sources collectively to plan to emit in excess of the collective state budgets. EPA believes that a well-established trading program would be able to function with an allowance bank lower than the full amount of the covered states' variability limits, as discussed in section VII.B.6 with respect to the proposed bank recalibration process that would begin with the 2024 control period. However, EPA also believes there are several compelling reasons in this instance to use a bank target higher than the minimum practicable level.

First, making an allowance bank available for use in the 2023 control period that is somewhat higher than the minimum practicable level would help to address concerns that might otherwise arise regarding the transition to a new set of compliance requirements, for some sources, and the transition to compliance requirements based on revised emissions budgets different from the emissions budgets that the sources had reason to anticipate under previous rulemakings, for the remaining sources. Although the EPA is confident that the emissions budgets being proposed in this rulemaking for the 2023 control period are readily achievable, the EPA also believes that the existence of a somewhat larger allowance bank at this transition point will promote sources' confidence in their ability to meet their 2023 compliance obligations in general and in a liquid allowance market in particular. Second, because the large majority of the remaining Group 2 allowances that would be converted to Group 3 allowances in this rulemaking are held by the sources currently in the Group 2 trading program, while the large majority of the initial bank of Group 3 allowances previously created in the conversion under the Revised CSAPR Update are held by the sources already in the Group 3 trading program, basing the conversion in this rulemaking on a target bank amount set in the same manner as the target bank amount used in the Revised CSAPR Update is expected to result in a less concentrated distribution of holdings of banked Group 3 allowances following the conversion than would be the case if a more stringent target bank amount were used under this rulemaking than was used in the Revised CSAPR Update. A lower concentration of holdings of banked Group 3 allowances would generally be expected to help ensure allowance market liquidity. Third, EPA considers it equitable to treat the sources in the states transitioning from the Group 2 trading program to the Group 3 trading program in this rulemaking roughly similarly to the sources in the states that transitioned between the same two trading programs in the Revised CSAPR Update with respect to the benefit they would receive under the Group 3 trading program for any efforts they may have made to make emissions reductions under the Group 2 trading program beyond the minimum efforts that were required to comply with the emissions budgets under that program. Finally, to the extent that the proposed conversion results in a larger bank of allowances remaining after the 2023 control period than is considered necessary to sustain a well-functioning trading program in subsequent control periods, the excess would be removed from the program in the proposed bank recalibration process that would be implemented starting with the 2024 control period and therefore would not weaken sources' incentives to control emissions on a permanent basis.

The EPA requests comment on the proposal to create additional banked Group 3 allowances through the conversion of Group 2 allowances banked for control periods before 2023.

c. Recall of Group 2 Allowances Allocated for Control Periods After 2022

To maintain the previously established levels of stringency of the Group 2 trading program for the states and sources that remain subject to that program under this proposed rule, the EPA proposes to recall CSAPR NO_X Ozone Season Group 2 allowances equivalent in amount and usability to all vintage year 2023–2024 CSAPR NO_X Ozone Season Group 2 allowances previously allocated to sources in Group 3 states and areas of Indian country and recorded in the sources' compliance accounts. The proposed recall provisions would apply to all sources in jurisdictions newly added to the Group 3 trading program in whose compliance accounts CSAPR NO_X Ozone Season Group 2 allowances for a control period in 2023 or 2024 were recorded, including sources where some or all units have permanently retired or where the previously recorded 2023–2024 allowances have been transferred out of the compliance account. The proposed recall provisions provide a flexible compliance schedule intended to accommodate any sources that have already transferred the previously recorded 2023–2024 allowances out of their compliance accounts and allows Group 2 allowances of earlier vintages to be surrendered to achieve compliance. Like the similar recall provisions finalized in the Revised CSAPR Update, the proposed recall provisions include specifications for how the recall provisions apply in instances where a source and its allowances have been transferred to different parties and for the procedures that the EPA will follow to implement the recall.

Under the Group 2 trading program regulations, each Group 2 allowance is a ''limited authorization to emit one ton of NO_X during the control period in one year,'' where the relevant limitations include the EPA Administrator's authority ''to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.'' 40 CFR 97.806(c)(6)(ii). The Administrator proposes to determine that, in order to effectively implement the Group 2 trading program as a compliance mechanism through which states not subject to the Group 3 trading program may continue to meet their obligations under CAA section 110(a)(2)(D)(i)(I) with regard to the 2008 ozone NAAQS, it is necessary to limit the use of Group 2 allowances equivalent in quantity and usability to all Group 2 allowances previously allocated for the 2023–2024 control periods and recorded in the compliance accounts of sources in the newly added Group 3 jurisdictions. The Group 2 allowances that have already been allocated to sources in the newly added Group 3 states for the 2023–2024 control periods and recorded in the sources' compliance accounts represent the substantial majority of the total remaining quantity of Group 2 allowances that have been allocated and recorded for the 2023–2024 control periods and that were not already made subject to recall when other jurisdictions were transferred from the Group 2 trading program to the Group 3 trading program in the Revised CSAPR Update. Because allowances can be freely traded, if the use of the 2023–2024 Group 2 allowances previously recorded in newly added Group 3 sources' compliance accounts (or equivalent Group 2 allowances) were not limited, the effect would be the same as if the EPA had issued to sources in the states that will remain covered by the Group 2 trading program a quantity of allowances available for compliance under the 2023–2024 control periods many times the levels that the EPA determined to be appropriate emissions budgets for these states in the CSAPR Update. Through the use of banked allowances, the excess Group 2 allowances would affect compliance under the Group 2 trading program in control periods after 2024 as well. Continued implementation of the Group 2 trading program at levels of stringency consistent with the levels contemplated under the CSAPR Update therefore requires that the EPA limit the use of the excess allowances, as the EPA is proposing here.

In this rulemaking, the EPA proposes to implement limitations on the use of the excess 2023–2024 Group 2 allowances through requirements to surrender, for each 2023–2024 Group 2 allowance recorded in a newly added Group 3 source's compliance account, one Group 2 allowance of equivalent usability under the Group 2 trading program. The surrender requirements would apply to the owners and operators of the Group 3 sources in whose compliance account the excess 2023–2024 Group 2 allowances were initially recorded. In general, each source's current owners and operators would be required to comply with the surrender requirements for the source by ensuring that sufficient allowances to complete the deductions are available in the source's compliance account by one of two possible deadlines discussed below. However, an exception would be provided if a source's current owners and operators obtained ownership and operational control of the source in a transaction that did not include rights to direct the use and transfer of some or all of the 2023–2024 Group 2 allowances allocated and recorded (either before or after that transaction) in the source's compliance account. The proposed rule provides that in such a circumstance, with respect to the 2023–2024 Group 2 allowances for which rights were not included in the transaction, the surrender requirements would apply to the most recent former owners and operators of the source before any such transactions occurred. Because in this situation a source's former owners and operators might lack the ability to access the source's compliance account for purposes of complying with the surrender requirements, the former owners and operators would instead be allowed to meet the surrender requirements with Group 2 allowances held in a general account.[300]

To provide as much flexibility as possible consistent with the need to limit the use of the excess Group 2 allowances, for each 2023–2024 Group 2 allowance recorded in a Group 3 source's compliance account, the EPA proposes to accept the surrender of either the same specific 2023–2024 Group 2 allowance or any other Group 2 allowance with equivalent (or greater) usability under the Group 2 trading program. Thus, a surrender requirement with regard to a Group 2 allowance allocated for the 2023 control period could be met through the surrender of any Group 2 allowance allocated for the 2023 control period or the control period in any earlier year—in other words, any 2017–2023 Group 2 allowance.[301] Similarly, the surrender requirement with regard to a 2024 Group 2 allowance could be met through the surrender of any 2017–2024 Group 2 allowance.

Owners and operators subject to the surrender requirements could choose from two possible deadlines for meeting the requirements. The first deadline would be 15 days after the effective date of a final rule in this rulemaking.[302] As soon as practicable or after this date, the EPA would make a first attempt to complete the deductions of Group 2 allowances required for each Group 3 source from the source's compliance account. The EPA would deduct Group 2 allowances first to address any surrender requirements for the 2023 control period and then to address any surrender requirements for the 2024 control period. When deducting Group 2 allowances to address the surrender requirements for each control period, EPA would first deduct allowances allocated for that control period and then would deduct allowances allocated for each successively earlier control period. This order of deductions is intended to ensure that whatever Group 2 allowances are available in the account are applied to the surrender requirements in a manner that both maximizes the extent to which all of the source's surrender requirements would be met and also ensures that any Group 2 allowances left in the source's compliance account after completion of all required deductions would be the earliest allocated, and therefore most useful, Group 2 allowances possible. Among the Group 2 allowances allocated for a given control period, The EPA would first deduct allowances that were initially recorded in that account, in the order of recordation, and would then deduct allowances that were transferred into that account after having been initially recorded in some other account, in the order of recordation.

Following the first attempt to deduct Group 2 allowances to address Group 3 sources' surrender requirements, the EPA would send a notification to the designated representative for each such source (as well as any alternate designated representative) indicating whether all required deductions were completed and, if not, the additional amounts of Group 2 allowances usable in the 2023 or 2024 control periods that must be held in the appropriate account by the second surrender deadline of September 15, 2023. Each notification would be sent to the email addresses most recently provided to the EPA for the recipients and would include information on how to contact the EPA with any questions. The EPA proposes that no allocations of Group 3 allowances would be recorded in a source's compliance account until all the source's surrender requirements with regard to 2023–2024 Group 2 allowances have been met. For this reason, the principal consequence to a source of failure to fully comply with the surrender requirements by 15 days after the effective date of a final rule would be that any Group 3 allowances allocated to the units at the source for the 2023 and 2024 control periods that would otherwise have been recorded in the source's compliance account by 30 days after the effective date of a final rule would not be recorded as of that recordation date.

If all surrender requirements of 2023–2024 Group 2 allowances for a source have not been met in EPA's first attempt, the EPA would make a second attempt to complete the required deductions from the source's compliance account (or from a specified general account, in the limited circumstance noted above) as soon as practicable on or after September 15, 2023. The order in which Group 2 allowances are deducted would be the same as described above for the first attempt.

If the second attempt to deduct Group 2 allowances to meet the surrender requirements through deductions from the source's compliance account (or

[300] The EPA is currently unaware of any source that would need to use this flexibility but has included the option in the proposal to address the theoretical possibility of such a situation.

[301] The first control period for the Group 2 trading program was in 2017.

[302] As discussed later in this section and in Section VII.B.9.b, the EPA is proposing to condition recordation of any allocations of Group 3 allowances in a source's compliance account on the source's prior compliance with the proposed recall requirements for Group 2 allowances. The purpose of providing a first deadline for the recall provisions 15 days after a final rule's effective would be to ensure that sources have an early opportunity to comply with the recall provisions in order to be eligible to have allocations of Group 3 allowances recorded in their accounts as proposed 30 days after the final rule's effective date. Because the vast majority of sources subject to the proposed recall provisions already hold sufficient Group 2 allowances to comply with the recall provisions, the EPA anticipates that the sources would easily be able to comply with the proposed first recall deadline.

from a specified general account) is unsuccessful for a given source, the EPA proposes that as soon as practicable on or after November 15, 2023, to the extent necessary to address the unsatisfied surrender requirements for the source, the EPA would deduct the 2023–2024 Group 2 allowances that were initially recorded in the source's compliance account from whatever accounts the allowances are held in as of the date of the deduction, except for any allowances where, as of April 1, 2022, no person with an ownership interest in the allowances was an owner or operator of the source, was a direct or indirect parent or subsidiary of an owner or operator of the source, or was directly or indirectly under common ownership with an owner or operator of the source.[303] Before making any deduction under this provision, the EPA would send a notification to the authorized account representative for the account in which the allowance is held and would provide an opportunity for submission of objections concerning the data upon which the EPA is relying. In EPA's view, this provision would not unduly interfere with the legitimate expectations of participants in the allowance markets because the provision would not be invoked in the case of any allowance that was transferred to an independent party in an arms-length transaction before EPA's intent to recall 2023–2024 Group 2 allowances became widely known. The provision would apply only to a Group 2 allowance that, as of April 1, 2022, was still controlled either by the owners and operators of the source in whose compliance account it was initially recorded or by an entity affiliated with such an owner or operator. The EPA believes that by April 1, 2022, all market participants will have had ample opportunity to become informed of the proposed rule provisions to recall 2023–2024 Group 2 allowances recorded in Group 3 sources' compliance accounts, particularly since the EPA implemented a closely analogous recall of Group 2 allowances in the Revised CSAPR Update.[304]

The EPA proposes that failure of a source's owners and operators to comply with the surrender requirements would be subject to possible enforcement as a violation of the CAA, with each allowance and each day of the control period constituting a separate violation.

To eliminate any possible uncertainty regarding the amounts of Group 2 allowances allocated for the 2023–2024 control periods (or earlier control periods) that the owners and operators of each Group 3 source would be required to surrender under the recall provisions, the EPA has prepared a list of the sources in the proposed additional Group 3 states and areas of Indian country in whose compliance accounts allocations of 2023–2024 Group 2 allowances were recorded, with the amounts of the allocations recorded in each such compliance account for the 2023 and 2024 control periods. An additional list shows, for each newly added Group 3 source, the specific Group 2 allowances (batched by serial number) allocated for each control period and recorded in the source's compliance account and indicates whether, as of December 31, 2021, that batch of allowances was held in the source's compliance account, in an account believed to be partially or fully controlled by a related party (*i.e.,* an owner or operator of the source or an affiliate of an owner or operator of the source), or in an account believed to be fully controlled by independent parties. The lists are in a spreadsheet titled, ''Recall of Additional CSAPR NO_X Ozone Season Group 2 Allowances'', available in the docket for this proposed rule. After the first and second surrender deadlines, the EPA intends to update the lists to indicate for each Group 3 source whether the surrender requirements for the source under the recall provisions have been fully satisfied. The EPA would post the updated lists on a publicly accessible website to ensure that all market participants have the ability to determine which specific 2023–2024 Group 2 allowances initially recorded in any given Group 3 source's compliance account do or do not remain subject to potential deduction to address the source's surrender requirements under the recall provisions.

The EPA requests comment on the proposal to recall Group 2 allowances equivalent in quantity and usability to the Group 2 allowances previously issued for the 2023 and 2024 control periods and recorded in the compliance accounts of sources in jurisdictions being newly added to the Group 3 trading program in this proposed rule.

12. Conforming Revisions to Other Regulations

As noted in Section VII.B.1.a of this proposed rule, in addition to the Group 3 trading program, EPA currently administers five other CSAPR trading programs, all of which have provisions that in most respects parallel the provisions of the Group 3 trading program.[305] The EPA also administers the Texas SO_2 Trading Program, whose provisions parallel the provisions of the CSAPR trading programs to a somewhat lesser extent.[306] In this rulemaking, in addition to the proposed revisions to the Group 3 trading program, the EPA is proposing a small number of conforming revisions to the other CSAPR trading programs and/or the Texas SO_2 Trading Program to maintain consistency across the regulations for the various trading programs to the extent possible.

The first set of proposed conforming revisions concerns the use of the term ''Indian country'' in the allowance allocation provisions of the regulations for all the CSAPR trading programs. As discussed in Section VII.B.9.a of this proposed rule, to reflect the D.C. Circuit's holding in *ODEQ* v. *EPA* that states have initial CAA implementation planning authority in non-reservation areas of Indian country until displaced by a demonstration of tribal jurisdiction over such an area, the EPA is proposing to revise the allowance allocation provisions in the Group 3 trading program regulations so that, instead of distinguishing between the sets of units within a given state's borders that either are not or are in Indian country, the revised regulations would distinguish between (1) the set of units within the state's borders that are not in Indian country or are in areas of Indian country covered by the state's CAA implementation planning authority and (2) the set of units within the state's borders that are in areas of Indian country not covered by the state's CAA implementation planning authority. For the same reasons stated in Section VII.B.9.a of this proposed rule for the

[303] The proposed provision under which the EPA would not deduct Group 2 allowances transferred to unrelated parties before April 1, 2022 from the transferees' accounts would not relieve the source to which the Group 2 allowances were originally allocated from the obligation to comply with the recall requirements. Specifically, the source would be required to comply with the recall requirements by obtaining and surrendering other Group 2 allowances.

[304] Even before publication of the proposed rule, the EPA posted information on its websites to notify market participants that a pending rulemaking could have consequences for the value and usability of Group 2 allowances. The posted locations included the electronic portal that authorized account representatives use to enter allowance transfers for recordation by the EPA in the Allowance Management System. Additionally, the EPA emailed a notice identifying the possibility of such consequences to the representatives for all Allowance Management System accounts.

[305] The regulations for the Group 3 Trading Program are at 40 CFR 97, subpart GGGGG. The regulations for the other five CSAPR trading programs are at 40 CFR part 97, subparts AAAAA, BBBBB, CCCCC, DDDDD, and EEEEE.

[306] The regulations for the Texas SO_2 Trading Program are at 40 CFR part 97, subpart FFFFF.

Group 3 trading program, the EPA proposes to make revisions to the allowance allocation provisions in the regulations for all the other CSAPR trading programs establishing the same substantive distinction among the sets of units within each state's borders. The specific regulatory provisions that would be affected are identified in Section X of this proposed rule. The EPA is unaware of any currently operating units that would be affected by this proposed revision to the regulations for the other CSAPR trading programs.

The second set of proposed conforming revisions concerns the schedule for recording allocations of allowances to existing units. To maintain consistency with the provisions of the revised Group 3 Trading Program to the extent possible, the EPA proposes to revise the regulations for each of the other five CSAPR trading programs and the Texas SO_2 Trading Program to reflect whatever revised schedule for recording most allowance allocations the EPA may adopt for the revised Group 3 trading program in a final rule in this rulemaking. The proposed revisions to the recordation deadlines would affect only the timing of recordation, not the amounts of allowances allocated to and recorded for any source for any control period.

The effect of the proposed revisions would be to establish a new common recordation schedule for all the CSAPR trading programs and the Texas SO_2 Trading Program. Assuming the common schedule adopted is the specific schedule proposed for the Group 3 trading program in Section VII.B.9 of this proposed rule, allocations from the portion of each state emissions budget under each program not reserved in a set-aside would be recorded by July 1 of the year immediately preceding the year of the relevant control period. Under the current regulations before the proposed revisions, the equivalent recordation deadline is July 1 of the year three years before the year of the relevant control period. Relatedly, the EPA also proposes to revise the deadline for states to submit any state-determined allocations to the EPA under each trading program to June 1 of the year immediately preceding the year of the relevant control period, instead of June 1 of the year three years before the year of the relevant control period.[307]

This EPA believes that revising the recordation schedules as proposed to establish a new common recordation schedule for the affected trading programs would make the programs procedurally more consistent, generally reducing the time and cost expended by sources to understand and comply with multiple trading programs. Greater consistency across the various programs would also support greater administrative efficiency by the EPA and by states that elect to determine allowances allocations under the various programs. In addition, by reducing the number of future control periods for which allowances are recorded, the proposed revisions would reduce the likelihood that the EPA might need to recall already-recorded allowances as part of a transition for some sources to new regulatory requirements in a future rulemaking. The EPA has implemented such a recall in the Revised CSAPR Update and has proposed to implement a similar recall in this rulemaking.

Finally, the EPA believes that revising the recordation schedules for the other CSAPR trading programs and the Texas SO_2 Trading Program as proposed would not adversely impact allowance market liquidity. Allowances issued for control periods through 2024 under each of these programs were recorded by July 1, 2020. As of December 2021, although recorded private transfers of earlier vintage allowances usable for 2021 compliance have been increasing in advance of the upcoming June 1, 2022, compliance deadline for the 2021 control periods, few allowances recorded for the 2023 or 2024 control periods (or even the 2022 control period) under any of the programs have been transferred out of the accounts in which they were initially recorded, except as needed to comply with the recall of certain allowances under the Revised CSAPR Update. Moreover, most of the recorded transfers of allowances issued for 2022, 2023, and 2024 have been between accounts controlled by the same entity, corporate affiliates, or other related entities (such as unit co-owners) rather than between accounts controlled by unrelated parties. The EPA therefore believes there would have been little effect on arms-length allowance market activity in these programs if the proposed revised recordation schedule had already been in effect and the allowances for 2023 and 2024 consequently had not yet been recorded.

Further details on the specific regulatory provisions that would be affected by the proposed revisions to allowance allocation recordation schedules are provided in Section X of the proposed rule.

The EPA requests comment on the proposed revision to the definition of ''Indian country'' under the CSAPR NO_X Annual, NO_X Ozone Season Group 1, SO_2 Group 1, SO_2 Group 2, and NO_X Ozone Season Group 2 Trading Programs and the proposed revisions to the allowance allocation recordation deadlines under the CSAPR NO_X Annual, NO_X Ozone Season Group 1, SO_2 Group 1, SO_2 Group 2, and NO_X Ozone Season Group 2 Trading Programs and the Texas SO_2 Trading Program.

C. Regulatory Requirements for Non-EGUs

The EPA is proposing that the FIPs for 23 of the states covered in this proposed rule will include new emissions limitations on emissions units in seven non-EGU industries that EPA finds (as discussed in Section VI of this proposed rule) to be significantly contributing to nonattainment or interfering with maintenance in other states.

In order to achieve the necessary non-EGU emissions reductions for the 23 states, the EPA proposes emissions limitations for the most impactful units in the relevant industries that are achievable with the control technologies identified in the Step 3 analysis. The EPA is proposing a direct control approach with rate-based limits, production-based limits, and work practice standards set on a uniform basis for the different segments of non-EGU emissions units using applicability criteria based on size and type of unit and, in some cases, emissions thresholds. The EPA believes this approach can achieve the requisite level of emissions reductions from the covered units through the assignment of emissions limits that are achievable across the entire segment. The EPA believes that establishing emissions limits for emissions units based on size and type of unit and, in some cases, emissions thresholds, will achieve the necessary reductions without requiring a unit-by-unit assessment.[308] By

[307] The regulations for the various programs already establish a common recordation schedule for the portion of each state emissions budget set aside for possible allocation to new units—namely, by May 1 of the year after the year of the relevant control period. The related deadline for states to submit any state-determined allocations of these allowances to the EPA under each program is April 1 of the year after the year of the relevant control period.

[308] If an emissions unit installs SCR or SNCR to meet an emissions limit in response to the proposed FIP that would be a physical change under new source review (NSR) and lead to an assessment of potential emissions changes. If the installation of SCR results in an emissions increase that exceeds the thresholds in the NSR regulations for one or more regulated NSR pollutants, including the

establishing uniform emissions limits for categories of units rather than on a unit-by-unit basis, the EPA can also ensure that any new source of emissions constructed after this proposed rulemaking are also subject to the emissions limits identified later (*see* Section IV.B.1.d of this proposed rule).

The EPA recognizes that the numerous variables that contribute to differences in units' emissions rates may complicate development of limits for groups of units as large as those addressed in this proposed rule. For each emissions source category, the EPA considered the range of emissions limits that currently apply to these sources under other CAA programs, such as RACT, NSPS, NESHAP, and OTC model rules, to develop an emissions limit that should be achievable by all sources after installing the controls identified in the Step 3 analysis. For a detailed discussion of the technical bases for EPA's proposed requirements for non-EGU emissions units, see the Non-EGU Sectors TSD.

The EPA is proposing that the emissions limits and compliance requirements for non-EGUs will apply only during the ozone season (which runs annually from May–September). This is consistent with EPA's prior practice in federal actions to eliminate significant contribution of ozone in the 1998 NO_X SIP Call, CAIR, CSAPR, CSAPR Update, and the Revised CSAPR Update. EPA is seeking comment on whether non-EGU sources would run controls that would be installed as a result of this proposed FIP year-round (*i.e.,* will some source categories run their controls year-round due to the nature of those controls?).

In addition, the EPA proposes to apply the FIP requirements to all existing emissions units and any future emissions units constructed after the promulgation of a final rule. Further, the non-EGU emissions limits and compliance requirements will apply in all 23 states (and, as discussed in Section IV.C.2 of this proposed rule, in areas of Indian country within the borders of those states), even if some of those states do not currently have emissions units in a particular source category. This approach will ensure that all new sources constructed in any of the 23 states will be subject to the same regulatory requirements as applied for the existing units under this proposed rule. This will also mitigate any potential incentive to move production from an existing non-EGU source in one linked state to a new non-EGU source of the same type but lacking the relevant emissions control requirements in another linked state.

At this time, this EPA is not proposing to include non-EGUs in the trading program described in this proposed rule. If EPA were to include non-EGUs in the trading program, we would require monitoring and reporting of hourly mass emissions in accordance with 40 CFR part 75 as we have required for all trading programs. Monitoring and reporting under part 75 include CEMS (or an approved alternative method), rigorous initial certification testing, and periodic quality assurance testing thereafter, such as relative accuracy test audits and daily calibrations. This type of consistent and accurate measurement of emissions is necessary to ensure each allowance actually represents 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. *See* 75 FR 45325 (August 2, 2010). Moreover, these monitoring requirements generally would need to be in place for at least one full ozone season to establish baseline data before it would be appropriate to rely on a trading program as the mechanism to achieve the required emissions reductions. Therefore, at this time, the EPA believes that applying unit-level emissions limitations on non-EGU emissions units rather than constructing an emissions trading regime is more administratively feasible and more easily implementable at the source level, and it will effectively eliminate each state's significant contribution without the need for establishing a new emissions trading program.

The EPA is proposing to require electronic reporting for all seven non-EGU industries. Specifically, owners and operators of affected units must submit electronic copies of required performance test reports, performance evaluation reports, quarterly and semi-annual reports, and excess emissions reports through EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI). The EPA is proposing to require that performance test results collected using test methods that are supported by EPA's Electronic Reporting Tool (ERT) as listed on the ERT website [309] at the time of the test be submitted in the format generated through the use of the ERT or an electronic file consistent with the xml schema on the ERT website, and that other performance test results be submitted in portable document format (PDF) using the attachment module of the ERT. Similarly, the EPA is proposing to require that performance evaluation results of CEMS measuring relative accuracy test audit (RATA) pollutants that are supported by the ERT at the time of the test be submitted in the format generated through the use of the ERT or an electronic file consistent with the xml schema on the ERT website, and that other performance evaluation results be submitted in PDF using the attachment module of the ERT. In addition, the EPA is proposing to require that quarterly and semi-annual reports and excess emissions reports be submitted in PDF uploaded in CEDRI.

The EPA is proposing to allow for an extension of time to file a report where an owner or operator demonstrates that it cannot meet the reporting deadline for reasons outside of its control. Specifically, the EPA has identified two broad circumstances under which the EPA may grant a request for an extension of time to file an electronic report. These circumstances are (1) outages of EPA's CDX or CEDRI which preclude an owner or operator from accessing the system and submitting required reports and (2) *force majeure* events, which are defined as events that will be or have been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevent an owner or operator from complying with the requirement to submit a report electronically. Examples of *force majeure* events are acts of nature, acts of war or terrorism, or equipment failure or safety hazards beyond the control of the facility. In both circumstances, the decision to grant an extension of time to report is within the discretion of the Administrator, and reporting should occur as soon as possible.

Electronic submittal of required reports will increase the usefulness of the data contained in those reports, is in keeping with current trends in data availability and transparency, will further assist in the protection of public health and the environment, will improve compliance by facilitating the ability of regulated facilities to demonstrate compliance with requirements and by facilitating the ability of the EPA to assess and determine compliance, and will ultimately reduce burden on regulated facilities and the EPA. Electronic reporting also eliminates paper-based, manual processes, thereby saving time and resources, simplifying data entry, eliminating redundancies, minimizing

netting analysis, the changes would trigger the applicability of NSR.

[309] *https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert.*

data reporting errors, and providing data quickly and accurately to the affected facilities, air agencies, EPA, and the public. Moreover, electronic reporting is consistent with EPA's plan [310] to implement Executive Order 13563 and is in keeping with EPA's agency-wide policy [311] developed in response to the White House's Digital Government Strategy.[312]

The EPA notes that no emissions standard or other requirement established for non-EGUs in these FIPs may be interpreted, construed, or applied to diminish or replace the requirements of any emissions limitation or other applicable requirement established by the Administrator pursuant to other CAA authority or a standard issued under State authority.

1. Pipeline Transportation of Natural Gas

Applicability

The EPA is proposing to establish regulatory requirements for the Pipeline Transportation of Natural Gas industry that apply to stationary, natural gas-fired, spark ignited reciprocating internal combustion engines (''stationary SI engines'') within these facilities that have a maximum rated capacity of 1,000 horsepower (hp) or greater. Based on our review of the potential emissions from stationary SI engines, we find that use of a maximum rated capacity of 1,000 hp reasonably approximates the selection of 100 tpy used within the non-EGU screening assessment. Therefore, stationary SI engines subject to the proposed rule requirements of this section are those found within any of the 23 covered states with non-EGU emissions reduction obligations that are within the Pipeline Transportation of Natural Gas industry and have a maximum rated capacity of 1,000 hp or greater.

Emissions Limitations and Rationale

In developing the emissions limits for the Pipeline Transportation of Natural Gas industry, EPA reviewed RACT NO_X rules, air permits, and OTC model rules. While some permits and rules express engine emissions limits in parts per million by volume (pmmv), the majority of rules and source-specific requirements express the emissions limits in grams per horsepower per hour (g/hp-hr). The EPA has historically set emissions limits for these types of engines using g/hp-hr and finds that method appropriate for this proposed FIP as well.

Based on the available information for this industry, applicable State and local air agency rules, and active air permits issued to sources with similar engines, the EPA is proposing the following emissions limits for stationary SI engines in the covered states:

TABLE VII.C–1—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR PIPELINE TRANSPORTATION OF NATURAL GAS

Engine type and fuel	Proposed NO_X emissions limit	Additional information
Natural Gas Fired Four Stroke Rich Burn	1.0 g/hp-hr	Limits reviewed ranged between 0.2 and 3.0 g/hp-hr.
Natural Gas Fired Four Stroke Lean Burn	1.5 g/hp-hr	Limits reviewed ranged between 0.5 and 3.0 g/hp-hr.
Natural Gas Fired Two Stroke Lean Burn	3.0 g/hp-hr	Limits reviewed ranged between 0.5 and 3.0 g/hp-hr.

With regard to four stroke rich burn engines, the EPA is proposing an emissions limit of 1.0 g/hp-hr. This limit is designed to be achievable by installing Non-Selective Catalytic Reduction (NSCR) on existing four stroke rich burn engines, as identified in the non-EGU screening assessment. Sources are free to install another control technology besides NSCR as long as the unit is still able to meet the emissions limit. In particular for four stroke rich burn engines, NSCR can be an effective control technology due to the low oxygen percentage in the exhaust. Efficient operation of the catalyst in NSCR requires the engine exhaust gases contain no more than 0.5 percent oxygen, which makes rich burn engines uniquely suitable to NCSR. Given that NSCR can achieve NO_X reductions of 90 to 99 percent, the EPA believes an emissions limit of 1.0 g/hp-hr should be readily achievable by all four stroke rich burn engines subject to this proposed rulemaking. The EPA is taking comment on whether a lower emissions limit is more appropriate since even an assumed reduction of 95 percent would result in most engines being able to achieve an emissions rate of 0.5 g/hp-hr. However, at this time, the EPA does not have the information necessary to determine if a lower emissions limit is achievable for the four stroke rich burn engines subject to the proposed rulemaking, and therefore, the EPA is proposing an emissions limit of 1.0 g/hp-hr.

With regard to four stroke lean burn engines, the EPA is proposing an emissions limit of 1.5 g/hp-hr. This limit is designed to be achievable by installing SCR on existing four stroke lean burn engines. Sources are free to install another control technology with or without SCR as long as the unit is still able to meet the emissions limit. For example, it might be more cost effective on an ongoing basis for some four stroke lean burn engines to install layered combustion controls alone or along with SCR to achieve the necessary emissions reductions. Information available to the EPA suggests that some four stroke lean burn engines can achieve 90% reductions from layered combustion controls alone, such as turbochargers and inter-cooling, pre-chamber ignition or high energy ignition, improved fuel injection control, air/fuel ratio control.[313] Independent of unit specific considerations, the EPA believes that four stroke lean burn engines subject to this proposed FIP can achieve an emissions limit of 1.5 g/hp-hr with the installation and operation of SCR or other control technologies at the marginal cost threshold of $7,500 per

[310] EPA's Final Plan for Periodic Retrospective Reviews, August 2011. Available at: *https://www.regulations.gov/document?D=EPA-HQ-OA-2011-0156-0154.*

[311] E-Reporting Policy Statement for EPA Regulations, September 2013. Available at: *https://www.epa.gov/sites/production/files/2016-03/documents/epa-ereporting-policy-statement-2013-09-30.pdf.*

[312] Digital Government: Building a 21st Century Platform to Better Serve the American People, May 2012. Available at: *https://obamawhitehouse.archives.gov/sites/default/files/omb/egov/digital-government/digital-government.html.* For more information on the benefits of electronic reporting, see the memorandum *Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules,* referenced earlier in this section.

[313] Ozone Transport Commission, *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions,* 35–39, October 17, 2012.

ton identified in the non-EGU screening assessment. While a lower emissions limit may be achievable with SCR for some four stroke lean burn engines, the achievability of those lower limits may depend on engine age and come with increased costs not accounted for in this proposed rule. The EPA is seeking comment on whether a lower and higher emissions limit is appropriate for these units.

For two stroke lean burn engines, the EPA is currently proposing an emissions limit of 3.0 g/hp-hr. This limit is designed to be achievable by retrofitting existing two stroke lean burn engines with layered combustion to achieve this emissions limit. Sources are free to install another control technology besides layered combustion as long as the unit is still able to meet the emissions limit. As identified in the non-EGU screening assessment, the EPA believes that layered combustion controls, such as improved airflow, improved fuel to air mixing, improved ignition, and modern engine electronic controls can be achieved on two stroke engines at the marginal cost threshold of $7,500 per ton. With these types of controls, the information currently available to the EPA indicates that the amount of achievable emissions reductions is unit specific and can range from a 60 to 90 percent reduction in NO_X emissions. The EPA estimates that existing uncontrolled two stroke lean burn engines would need to reduce emissions by about 80 percent to comply with a 3.0 g/hp-hr emissions limit. While some RACT and model rules reviewed contained more stringent emissions limits for two stroke lean burn engines, the EPA does not have information adequate to conclude that the two stroke lean burn engines across all 23 states can meet a lower limit. Further, some information available supports a finding that an emissions limit below 3.0 g/hp-hr might not be achievable with layered combustion controls alone for some units, and those units would require additional controls beyond our cost threshold.[314] Therefore, the EPA is proposing an emissions limit of 3.0 g/bhp-hr for two stroke engines. The EPA is seeking comment on whether a lower emissions limit would be achievable with layered combustion alone for the sources covered by this FIP. Further, the EPA is seeking comment on whether additional control technology could be installed on these sources at or below the marginal cost threshold to achieve a lower emissions rate.

Compliance Assurance Requirement

The EPA is proposing to require stationary SI engines subject to this proposed FIP to conduct semi-annual performance testing in accordance with 40 CFR 60.8 to ensure that the engine is meeting the NO_X emissions limit. The EPA is proposing that affected engines then monitor and record hours of operation and fuel consumption to calculate ongoing compliance with the applicable emissions limit. In addition, the EPA is proposing that affected engines would use continuous parametric monitoring systems (CPMS) to ensure that the NO_X emissions limit is being met at all times. For example, engines utilizing layered combustion controls would need to monitor and record temperature, air to fuel ratio, and other parameters as appropriate to ensure that combustion conditions are optimized to reduce NO_X emissions and assure compliance with the emissions limit. For engines using SCR or NSCR, the EPA is proposing that source monitor and record parameters such as inlet temperature to the catalyst and pressure drop across the catalyst.

The EPA is seeking comment on whether it is feasible or appropriate to require affected engines to be equipped with continuous emissions monitoring systems (CEMS) to measure and monitor the NO_x emissions instead of conducting performance tests on a semiannual basis.

2. Cement and Concrete Product Manufacturing

Applicability

The EPA is proposing to establish regulatory requirements for the Cement and Concrete Product Manufacturing source category that apply to emissions units (kilns) that directly emit or have the potential to emit 100 tpy or more of NO_X. Further, the EPA is proposing emissions limits based on type of unit to ensure that the necessary NO_X emissions reductions occur. The EPA is seeking comment on whether it should set an applicability threshold based on a unit's design production capacity rather than an emissions threshold.

Emissions Limitations and Rationale

In developing the emissions limits for the Cement and Concrete Manufacturing industry, the EPA reviewed RACT NO_X rules, air permits, and consent decrees. These rules and source-specific requirements most commonly express the emissions limits for this industry in terms of mass of pollutant emitted (pounds) per kiln's clinker output (tons), *i.e.,* pounds of NO_X emitted per ton of clinker produced. A regulated entity routinely monitors and keeps track of its clinker output as it pertains to a kiln design capacity and the plant's production. Therefore, the EPA believes that this form of NO_X emissions limit is effective, practicable and convenient to record and report to an air agency.

In determining the averaging time for the limit, the EPA considered the NSPS for Portland Cement Plants at 40 CFR part 60, subpart F. Section 60.62(a)(3) of this subpart establishes a 30-operating day rolling average period for the NO_X emitted per ton of clinker produced and further states that an operating day includes all valid data obtained in any daily 24-hour period during which the kiln operates and excludes any measurements made during the daily 24-hour period when the kiln was not operating. In addition, 40 CFR 60.44b(i) requires that compliance with the applicable NO_X emissions limit be determined on a 30-day rolling average basis. The EPA is proposing to require a 30-operating day rolling average period as the averaging time frame for this particular industry. The proposed averaging timeframe is consistent with the longstanding national technology-based NSPS for this industry at 40 CFR part 60, subpart F. Furthermore, an air agency may choose to require an averaging period shorter than a 30-operating day rolling average in air permit(s) issued to these plants. The EPA finds that a 30-operating day rolling average period provides a reasonable balance between short term (hourly or daily) and long term (annual) averaging periods, while being flexible and responsive to fluctuations in operations and production.

Based on the available information for this industry, applicable State and local air agency rules, and active air permits or enforceable orders issued to affected cement plants, the EPA is proposing the following emissions limits for cement kilns:

[314] Ozone Transport Commission, *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions* at 24–25.

TABLE VII.C–2—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR KILN TYPES IN CEMENT AND CONCRETE PRODUCT MANUFACTURING

Kiln type	Proposed NO_X emissions limit (lb/ton of clinker)	Additional information
Long Wet	4.0	Limits reviewed ranged between 3.88–5.2; one State rule allows as high as 6.0; with addition of a post combustion NO_X control the upper range could be reduced significantly.
Long Dry	3.0	Limits reviewed showed 5.1; with addition of post combustion NO_X control the limit could be reduced significantly; limit of 3.0 would achieve a 41% reduction in NO_X emissions.
Preheater	3.8	Limits reviewed ranged between 1.5–3.44; limit of 3.8 is consistent with 30 TAC 117.3110(a)(3) and 35 IAC 217.224(a).
Precalciner	2.3	Requires post combustion NO_X control; consistent with permit A0017 for Lehigh Southwest Cement Company issued on May 5, 2020 by the Bay Area Air Quality Management District.
Preheater/Precalciner	2.8	Limits reviewed ranged between 1.8–3.4; limit of 2.8 is consistent with 30 TAC 117.3110(a)(4); Mitsubishi Cement Corporation Lucerne Valley Federal Operating Permit 11800001 issued by the Mojave Desert Air Quality Management District (MDAQMD) June 18, 2020; MDAQMD Rule 1161 (C)(2); and Illinois 35 IAC 217.224(a).

Although the EPA is proposing NO_X emissions limits based on the specific kiln types listed in Table VII.C–2, to provide operational flexibility the EPA is also proposing a source cap limit expressed in tons per day (tpd) of NO_X for each individual cement plant according to the following equation.

$$CAP2015\ Ozone\ Transport = \frac{(KW\ x\ NW) + (KD\ x\ ND)}{(2000\frac{pounds}{ton}\ x\ 365\frac{days}{year})}$$

Where:

CAP2015 Ozone Transport = total allowable NO_X emissions from all cement kilns located at one cement plant, in tons per day, on a 30-operating day rolling average basis;

KD = 1.7 pounds NO_X per ton of clinker for dry preheater-precalciner or precalciner kilns;

KW = 3.4 pounds NO_X per ton of clinker for long wet kilns;

ND = the average annual production in tons of clinker plus one standard deviation for the three most recent calendar years from all dry preheater-precalciner or precalciner kilns located at one cement plant; and

NW = the average annual production in tons of clinker plus one standard deviation for the three most recent calendar years from all long wet kilns located at one cement plant.

An affected cement plant will need to comply with both the source cap limit and the specific NO_X emissions limits assigned to its individual kiln type(s). The EPA notes that the above source cap would be calculated and assigned to operating kilns in a particular plant. That is, the total allowable NO_X emissions in tpd from one plant cannot be traded with another plant, regardless of these plants' control of ownership or operator's status, or regardless of these plants' proximity to each other or their location.

The EPA is soliciting comment on whether it is feasible or appropriate to phase out and retire existing long wet kilns in the affected states and to replace them with more energy efficient and less emitting units like preheater/precalciner installations. The EPA is also requesting comment on the time needed to complete such a task. It has been shown that such kilns replacements (preheater/precalciner kilns), when equipped with post-combustion NO_X control devices such as SNCR, are capable of meeting NO_X emissions limit of 1.5 lb/ton of clinker on a 30-operating day basis. For this reason, the EPA proposes to find that conversion from long wet kilns to preheater/precalciner installations is generally feasible. Given that long wet kilns are less energy efficient and generally emit more NO_X than other kiln types, conversion to preheater/precalciner installations would be the most effective method of NO_X reduction (per ton of clinker produced).

Additionally, EPA is soliciting comments on whether it is feasible or appropriate to require sources with existing preheater/precalciner kilns in the affected states that currently utilize low NO_X burners, combustion controls, staged combustion, or mid-kiln firing to add and operate a post combustion control device like SNCR or SCR to further improve their NO_X removal efficiency and lower NO_X emissions to 1.95 lb/ton of clinker or less. The EPA is also requesting comments on the time needed to complete such an addition.

We note that the EPA previously stated that it expects that the controls for cement kilns would take at least 2 years to install on a sector-wide basis across the 12-state region affected by the Revised CSAPR Update.[315]

Compliance Assurance Requirements

The EPA is proposing that performance tests be conducted on a semiannual basis. Such tests shall be conducted in conformance with the requirements of 40 CFR 60.8. Stack tests will need to conform with the Test Methods and Procedures in 40 CFR 60 appendix A, or other EPA-approved (federally enforceable) test methods and procedures.

The EPA is soliciting comments on whether it is feasible or appropriate to require affected units (kilns) to be equipped with CEMS to measure and monitor the NO_X concentration (emissions level) instead of conducting performance tests on semiannual basis.

We are also soliciting comment on whether it is appropriate for the affected units (kilns) to use CPMS instead of CEMS to monitor the NO_X concentration (emissions level). We note that CPMS, also called parametric monitoring, measures a parameter (or multiple parameters) as a key indicator of system performance. The parameter is generally an operational parameter of the process

[315] 85 FR 68999 (October 30, 2020).

or the air pollution control device (APCD) that is known to affect the emissions levels from the process or the control efficiency of the APCD. Examples of parametric monitoring include kiln feed rate, clinker production rate, fuel type, fuel flow rate, specific heat consumption, secondary air temperature, kiln feed-end temperature, preheater exhaust gas temperature, induced draught fan pressure drop, kiln feed-end percentage oxygen, percentage downcomer oxygen, primary air flow rate, ammonia feed rate and slippage.

3. Iron and Steel Mills and Ferroalloy Manufacturing

Applicability

The EPA is proposing to establish regulatory requirements for the Iron and Steel Mills and Ferroalloy Manufacturing source category that apply to emissions units that directly emit or have the potential to emit 100 tpy or more of NO_X and to facilities containing two or more such units that collectively emit or have the potential to emit 100 tpy or more of NO_X. The EPA is setting emissions limits based on type of unit to ensure that the necessary emissions reductions occur across all units of the same type. The EPA is seeking comment on whether it should set an applicability threshold based on a unit's production capacity rather than an emissions threshold.

Emissions Limitations and Rationale

In developing the emissions limits for the Iron and Steel and Ferroalloy Manufacturing industry, the EPA reviewed RACT NO_X rules, NESHAP rules, air permits and related emissions tests, technical support documents, and consent decrees. These rules and source-specific requirements most commonly express the emissions limits for this industry in terms of mass of pollutant emitted (pounds) per operating hour (hours) (*i.e.,* pounds of NO_X emitted per production hour), pounds per energy unit (*i.e.,* million British thermal unit (mmBtu)), or pounds of NO_X per ton of steel produced. A regulated entity routinely monitors and keeps track of its production in terms of tons of steel produced per hour (heat rate) as it pertains to the facility's rate of iron and steel production. Depending on the type of unit and industry practice, the EPA is proposing rate-based emissions limits in the form of lb/mmBtu, production-based limits in the form of lb/ton, and work practice standards.

In determining the averaging times for the limits, EPA initially reviewed the NESHAP for Iron and Steel Foundries codified at 40 CFR part 63 subpart EEEEE, the NESHAP for Integrated Iron and Steel manufacturing facilities codified at 40 CFR part 63 subpart FFFFF, the NESHAP for Ferroalloys Production: Ferromanganese and Silicomanganese codified at 40 CFR part 63 subpart XXX, and the NESHAP for Ferroalloys Production Facilities codified at 40 CFR part 63 subpart YYYYYY. EPA also reviewed various RACT NO_X rules from states located within the OTR, several of which have chosen to implement OTC model rules and recommendations. Based on this information, the EPA is proposing to require a 30-operating day rolling average period as the averaging time frame for this particular industry. The EPA finds that a 30-operating day rolling average period provides a reasonable balance between short term (hourly or daily) and long term (annual) averaging periods, while being flexible and responsive to fluctuations in operations and production.

Based on the available information for this industry, applicable federal and state rules, and active air permits or enforceable orders issued to affected facilities in the iron and steel and ferroalloy manufacturing industry, the EPA proposes the following emissions limits:

TABLE VII.C–3—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR IRON AND STEEL AND FERROALLOY EMISSIONS UNITS

Emissions unit	Proposed NO_X emissions standard or requirement (lbs/hour or lb/mmBtu)	Additional information
Blast Furnace	0.03 lb/mmBtu	OH NO_X RACT rules limit NO_X emissions from blast furnaces to 0.06 lb/mmBtu without requiring specific control technology. Control NO_X at stoves (typically 3 or 4 per blast furnace), assuming 40–50% reduction) by burner replacement plus SCR.
Basic Oxygen Furnace	0.07 lb/ton	Potential 25–50% reduction by SCR/SNCR from 0.14 lb/ton based on emissions testing.
Electric Arc Furnace	0.15 lb/ton steel	Example permit limits at around 0.2 lb/ton. Assumes 25% reduction by SCR to achieve 0.15 lb/ton steel.
Ladle/tundish Preheaters	0.06 lb/mmBtu	Nucor Kankakee BACT permit limit issued January 2021 is 0.1 lb/mmBtu, 2021. Assume 40% reduction by SCR.
Reheat furnace	0.05 lb/mmBtu	Sterling Steel permit, issued 2019: Low-NO_X natural gas fired burners designed to emit no more than 0.073 lb NO_X/mmBtu, Ohio RACT limit is 0.09 lb/mmBtu. Assume 40% reduction by SCR.
Annealing Furnace	0.06 lb/mmBtu	Big River Steel (AR) 2018 limit and Benteler Steel (LA) 2019 limit (0.11 lb/mmBtu), 85 mmBtu/hr and 13 mmBtu/hr, respectively. Lowest was 0.0915 lb/mmBtu, Nucor AR. Assume 40% reduction by SCR.
Vacuum Degasser	0.03 lb/mmBtu	0.05 lb/mmBtu Nucor Darlington (SC) and Nucor Tuscaloosa (AL). Assume 40% reduction by SCR.
Ladle Metallurgy Furnace	0.1 lb/ton	Assume 40% reduction by SCR.
Taconite Production Kilns	Work practice standard to install and operate low NO_X burners.	Consistent with requirements in Minnesota Taconite FIP *See 81 FR 21671.*
Coke Ovens (charging)	0.15 lb/ton of coal charged	Assume 50% reduction staged combustion and/or limited use SCR/SNCR during charging operations from AP–42 0.3 lb/ton emission factor.
Coke Ovens (pushing)	0.015 lb/ton of coal pushed	SunCoke Middletown limit is 0.02 lb/ton of coal. Assume 25% reduction by SCR.
Boilers—Coal	0.20 lb/mmBtu	See explanation in Section VII.C.5.
Boilers—Residual oil	0.20 lb/mmBtu	See explanation in Section VII.C.5.
Boilers—Distillate oil	0.12 lb/mmBtu	See explanation in Section VII.C.5.

TABLE VII.C–3—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR IRON AND STEEL AND FERROALLOY EMISSIONS UNITS—Continued

Emissions unit	Proposed NO_X emissions standard or requirement (lbs/hour or lb/mmBtu)	Additional information
Boilers—Natural gas	0.08 lb/mmBtu	See explanation in Section VII.C.5.

Due to the many types of units within Iron and Steel Mills and Ferroalloy Manufacturing facilities that are not currently subject to NO_X limitations of the stringency necessary to eliminate significant contribution, most of the emissions limits in this proposed rule are based on examples of permitted emissions and estimated reduction potential from the identified control technology. Based on the selection of SCR, SNCR, and burner replacement in the non-EGU screening assessment, the EPA assumed reductions of 20 to 50 percent from current permitted limits and emissions tests depending on the type of unit and controls being implemented.

In addition, for Taconite Production Kilns, the EPA does not currently have the data to determine appropriate emissions limits that these units could achieve by installing low NO_X burners. Therefore, the EPA is proposing to require the installation of low NO_X burners for Taconite Production Kilns and work practice standards for operating these control technologies to achieve emissions reductions. The EPA is also proposing to require these sources to perform performance tests and establish a unit-specific emissions limit at that time. These work practice standards are consistent with EPA's Taconite FIP for Minnesota. *See* 81 FR 21671 (April 12, 2016). Due to the ongoing nature of this FIP, the EPA is proposing to require installation of specific control technologies and a period of evaluation before setting a numerical emissions limit.

Compliance Assurance Requirements

The EPA is proposing to require each owner or operator of an affected facility that is subject to the NO_X emissions limit for Iron and Steel Mills and Ferroalloy Manufacturing emissions units contained in this section to install, calibrate, maintain, and operate a CEMS for the measurement of NO_X emissions discharged into the atmosphere from the affected facility. The EPA is proposing that each emissions unit will be required to conduct an initial performance test and to operate CEMS to assure compliance. In conducting the performance tests to demonstrate compliance, sources must use test methods and procedures in 40 CFR 60 appendix A, Method 7E, or other EPA-approved (federally enforceable) test methods and procedures. The EPA is also soliciting comments on alternative monitoring systems or methods that are equivalent to CEMS to demonstrate compliance with the emissions limits.

4. Glass and Glass Product Manufacturing

Applicability

The EPA is proposing to establish regulatory requirements for the Glass and Glass Product Manufacturing source category that apply to emissions units that directly emit or have the potential to emit 100 tpy or more of NO_X. The EPA is setting emissions limits based on type of unit to ensure that the necessary emissions reductions occur. The EPA is seeking comment on whether it should set an applicability threshold based on a unit's production capacity rather than an emissions threshold.

Emissions Limitations and Rationale

In developing the emissions limits for the Glass and Glass Product Manufacturing industry, the EPA reviewed RACT NO_X rules, air permits, Alternative Control Techniques (ACT), and consent decrees. These rules and source-specific requirements most commonly express the emissions limits for this industry in terms of mass of pollutant emitted (pounds) per weight of glass removed from the furnace (tons), *i.e.,* pounds of NO_X emitted per ton of glass produced. A regulated entity routinely monitors and keeps track of its glass outputs as it pertains to a furnace's design capacity and the plant's production. Therefore, the EPA believes that this form of NO_X emissions limit is effective, practicable, and convenient to record and report to an air agency.

In determining the averaging time for the limits, the EPA initially reviewed the NSPS for glass manufacturing plants codified at 40 CFR part 60 subpart CC. This NSPS applied to any glass melting furnace in an affected facility that commenced construction or modification after June 15, 1979, and produced more than 5 tons of glass per day. It was noted that the NSPS only provides standards for particulate matter and does not provide standards or averaging times for NO_X. In order to determine the averaging time for the NO_X emissions limits, the EPA reviewed various RACT NO_X rules from states located within the OTR, several of which have chosen to implement OTC model rules and recommendations.

Most of the states within the OTR implement RACT regulations for the glass manufacturing industry that do not specify presumptive NO_X limits.[316] With respect to those RACT rules in the OTR states that contain presumptive RACT NO_X limits for glass manufacturing furnaces, EPA found variations in averaging times, ranging from a 30-day rolling average to a more stringent daily average.[317] The EPA also reviewed RACT NO_X regulations for the glass manufacturing industry outside the OTR and observed that 30-day rolling averages and daily averages varied throughout the states.[318] The EPA is proposing to require owners or operators of glass manufacturing furnaces to comply with the applicable presumptive NO_X emissions limits on a 30-day rolling average time frame. This averaging time frame is consistent with other statewide RACT NO_X regulations for this particular industry. Furthermore, a state's air agency may choose to require an averaging period shorter than a 30-operating day rolling

[316] RACT NO_X rules of the following OTR states CT, DC, DE, MD, ME, NH, NY, RI, VA, and VT do not provide presumptive NO_X limits for glass manufacturing sources. These RACT regulations require owners or operators to submit RACT case-by-case analysis.

[317] Pennsylvania's presumptive RACT NO_X emissions limits are based on 30-day rolling average. New Jersey's and Massachusetts' rules contain more stringent daily averages. Maryland's RACT rule, section 26.11.09.08.I, requires owner or operators to optimize combustion by performing daily oxygen tests and maintain excess oxygen at 4.5% or less. See *http://www.dsd.state.md.us/comar/comarhtml/26/26.11.09.08.htm.*

[318] For example, presumptive RACT NO_X emissions limits in California are based on both 30-day rolling and daily averages (*see https://www.valleyair.org/rules/currntrules/R4354%20051911.pdf*). Wisconsin's NO_X emissions limits are based on a 30-day rolling average (*see https://casetext.com/regulation/wisconsin-administrative-code/agency-department-of-natural-resources/environmental-protection-air-pollution-control/chapter-nr-428-control-of-nitrogen-compound-emissions/subchapter-iv-NOX-reasonably-available-control-technology-requirements/section-nr-42822-emission-limitation-requirements*).

average in air permits or RACT regulations for these plants. The EPA finds that a 30-operating day rolling average period provides a reasonable balance between short term (hourly or daily) and long term (annual) averaging periods, while being flexible and responsive to fluctuations in operation and production.

Based on the available information for this industry, applicable state and local air agency rules, and active air permits or enforceable orders issued to affected glass manufacturing plants, EPA is proposing the following emissions limits for glass manufacturing furnaces:

TABLE VII.C–4—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR FURNACE UNIT TYPES IN GLASS AND GLASS PRODUCT MANUFACTURING

Furnace type	Proposed NO_X emissions limit (lb/ton of glass produced)	Additional information
Container Glass Manufacturing Furnace.	4.0	Limits reviewed ranged between 1–4; one state rule allowed as high as 5; with addition of post combustion NO_X controls, the upper range could be reduced significantly; consistent with 25 Pennsylvania Code 129.304(a)(1) and New Jersey Administrative Code 7:27 Subchapter 19.1.
Pressed/Blown Glass Manufacturing Furnace or Fiberglass Manufacturing Furnace.	4.0	Limits reviewed ranged between 1.36–4; one state rule allowed as high as 7; with addition of post combustion control the limit could be reduced significantly; limit of 4.0 is consistent with RACT regulations for states located within OTR.
Flat Glass Manufacturing Furnace.	9.2	Limits reviewed ranged between 5–9.2; with the addition of post combustion controls the limit could be reduced significantly; consistent with San Joaquin Valley Air Pollution Control District Rule 4354 5.1.1 and New Jersey Administrative Code 7:27 Subchapter 19.1.

The EPA is soliciting comment on whether it is feasible or appropriate to phase out and retire existing glass manufacturing furnaces in the affected states and replace them with more energy efficient and less emitting units like all-electric melter installations. The EPA is also requesting comment on the time needed to complete such a task. All-electric melters are glass melting furnaces in which all the heat required for melting is provided by electric current from electrodes submerged in the molten glass.[319] All-electric melter furnaces could provide an energy efficient and NO_X emission-free alternative to current methods of melting and producing glass.

According to the EPA's ''Alternative Control Techniques Document—NO_X Emissions from Glass Manufacturing,'' [320] glass manufacturing furnaces may utilize combustion modifications equivalent to low-NO_X burners and oxy-firing. The EPA is soliciting comment on whether it is feasible or appropriate to require sources with existing glass manufacturing furnaces in affected states that currently utilize these combustion modifications to add and operate a post-combustion control device like SNCR and SCR to further improve their NO_X removal efficiency. The EPA is also requesting comments on the time needed to install such controls.

Compliance Assurance Requirements

The EPA is proposing to require each owner or operator of an affected facility that is subject to the NO_X emissions standards for glass manufacturing furnaces contained in this section to install, calibrate, maintain, and operate a CEMS for the measurement of NO_X emissions discharged into the atmosphere from the affected facility. The EPA is also soliciting comments on alternative monitoring systems or methods that are equivalent to CEMS to demonstrate compliance with the emissions limits. In conducting the performance tests to demonstrate compliance, sources must use test methods and procedures in 40 CFR part 60 appendix A, method 7E, or other EPA-approved (federally enforceable) methods and procedures. Owners or operators must calculate and record the 30-operating day rolling emissions rate of NO_X as the total of all hourly emissions data for a glass manufacturing furnace in the preceding 30 days, divided by the total tons of glass produced in that furnace during the same 30-operating day period. Owners or operators of glass manufacturing furnaces installed with continuous emissions monitoring may demonstrate compliance with the emissions limit as follows: (1) Determine the average pounds of NO_X emitted per day, (2) determine the tons of glass removed per day during the same day, (3) divide the average pounds of NO_X emitted per day by the tons of glass removed per day as determined in step (2), and (4) compare the quotient to the emissions limits prescribed in the Section VII of this proposed rule. If the pollutant mass emissions rate is in lb/hr, the following equation [321] shall be used to convert the emissions rate to lb pollutant/ton of glass pulled:

$$lb\ emitted / ton\ of\ glass\ pulled = \frac{\frac{lb}{hr} emitted}{Pull\ rate\ in \frac{tons}{hr}}$$

[319] *See* definitions in 40 CFR part 60 subpart CC.

[320] ''Alternative Control Techniques Document—NO_X Emissions from Glass Manufacturing,'' EPA–453/R–94–037, June 1994.

[321] This equation is provided in the San Joaquin Valley Unified Air Pollution Control District's Rule 4354, section 8.1.

5. Boilers From Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills

Applicability

The EPA is proposing to establish regulatory requirements for the Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills industries that apply to boilers within these facilities that have a design capacity of 100 mmBtu/hr or greater. These requirements are consistent with EPA's findings at Step 3 with respect to Tier 2 non-EGU industries. As noted below, we do not believe boilers meeting this size classification exist within the other Tier 2, or Tier 1 industries, but if they do, the EPA proposes that they would also be subject to the requirements of this part. Based on our review of the potential emissions from industrial boilers of various fuel types, we find that use of a boiler design capacity of 100 mmBtu/hr reasonably approximates the selection of 100 tpy used within the Non-EGU Screening Assessment memorandum. Therefore, boilers subject to the requirements of this section of the proposed rule are those found within any of the 23 covered states with non-EGU emissions reduction obligations that are within a Tier 1 or Tier 2 industry and have a design capacity of 100 mmBTU/hr or greater. The EPA is seeking comment on whether EPA should alternatively set an applicability threshold based on potential to emit.

Emissions Limitations and Rationale

This section of the proposed rule applies to certain boilers located at any facility identified as a Tier 2 industry within the non-EGU screening assessment. As described within the Non-EGU Screening Assessment memorandum, the EPA reviewed the projected 2026 emissions data to identify large boilers within the Tier 2 industries, defined as boilers projected to emit more than 100 tons per year in 2026. Boilers meeting this threshold were found in three of the five Tier 2 industries, as identified in Table VII.C.5–1.

TABLE VII.C.5–1—TIER 2 INDUSTRIES WITH LARGE BOILERS AND ASSOCIATED NAICS CODES

Industry	NAICS code
Basic Chemical Manufacturing	3251xx
Petroleum and Coal Products Manufacturing	3241xx
Pulp, Paper, and Paperboard Mills	3221xx

The EPA did not find large boilers within the Lime and Gypsum Product Manufacturing (NAICS code 3274xx) or the Metal Ore Mining industries (NAICS code 2122xx). As such the EPA is not expressly proposing to include boilers in those industries. However, if as a result of receiving additional information during the comment period the EPA identifies large boilers within these two industries that meet the applicability criteria described below, those boilers could be subject to the requirements of the final rule.

As described within the Non-EGU Sectors TSD, the RACT rules we reviewed containing NO_X limits for industrial boilers relied primarily on design capacity in mmBtu/hr as the metric for selecting design criteria. The EPA is proposing to use that same metric to establish control requirements for boilers with a design capacity of 100 mmBtu/hr or greater. As noted within the Non-EGU Sectors TSD, boilers rated at 100 mmBtu/hr or greater can emit large amounts of NO_X, particularly if they do not operate NO_X control equipment.

The EPA reviewed NO_X emissions limits for industrial boilers with design capacities of 100 mmBtu/hr or greater that have been adopted by states and incorporated into their SIPs. The Non-EGU Sectors TSD contains a detailed discussion of that evaluation. Based on our review, we propose to establish the following NO_X emissions limits for coal, oil, and gas fired industrial boilers located at a Tier 2 industry:

TABLE VII.C.5–2—PROPOSED NO_X EMISSIONS LIMITS FOR INDUSTRIAL BOILERS >100 MMBTU/HR

Unit type	Emissions limit (lbs NO_X/mmBtu)	Additional information
Coal	0.20	Limits reviewed ranged from 0.08 to 1.0. Proposed limit will likely require a combination of combustion controls or post-combustion controls.
Residual oil	0.20	Limits reviewed ranged from 0.15 to 0.50. Proposed limit will likely require combustion controls.
Distillate oil	0.12	Limits reviewed ranged from 0.10 to 0.43. Proposed limit will likely require combustion controls.
Natural gas	0.08	Limits reviewed ranged from 0.06 to 0.25. Proposed limit will likely require a combination of combustion controls or post-combustion controls.

Additional information on the EPA's derivation of these proposed emissions rates for boilers is provided below and in the Non-EGU Sectors TSD.

The EPA notes that some coal, oil, and gas-fired industrial boilers may have already installed combustion or post-combustion control equipment, such as SCR or SNCR, sufficient to meet the emission limits established in this FIP. Some of the boilers covered by this FIP might have install controls to meet the emission limits contained within EPA's NSPS located at 40 CFR 60 Subpart Db, which requires that some fossil fuel-fired units that commenced construction, modification, or reconstruction after June 19, 1984, meet various NO_x emission limits based on factors such as unit type or heat rate. Additionally, industrial boilers located in ozone nonattainment areas or within the ozone transport region may have installed controls to meet emission limits adopted by states to meet NO_x RACT requirements.

a. Coal-Fired Industrial Boilers

Coal-fired industrial boilers subject to the proposed requirements of this section would have to meet a NO_X emissions limit of 0.2 lbs/mmBtu on a 30-day rolling average basis.

Various forms of combustion and post-combustion NO_X control technology exist that should enable most facilities to be retrofit with equipment that will enable them to meet these emissions limits. Additionally, as noted in the Non-EGU Sectors TSD, many states containing ozone nonattainment areas or located within the OTR have already adopted emissions limits similar to or more stringent than the limits the EPA proposes here. Furthermore, some coal-fired industrial boilers may have installed combustion or post-combustion control equipment to meet the emissions limits contained within EPA's NSPS located at 40 CFR part 60 subpart Db, which requires that coal-fired industrial boilers meet a NO_X emissions limit of between 0.5 and 0.8

lbs/mmBtu depending on unit type.[322] Enhancements to or retrofit of additional NO_X control technology should enable most sources to meet the proposed NO_X limit.

There are two main types of NO_X control technology that we believe can be retrofit to most existing industrial boilers, or incorporated into the design of new boilers, to meet our proposed emissions limits. These two control types are combustion controls and post-combustion controls, and in some instances both types are used together. As noted in the EPA's ''Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (ICI) Boilers'' (hereafter ''ICI Boiler ACT''),[323] the type of NO_X control available for use on a particular unit depends primarily on the type of boiler, fuel type, and fuel-firing configuration. For example, Table 2–3 of the ICI Boiler ACT indicates which types of combustion and post-combustion NO_X controls are suitable to various types of coal-fired ICI boilers. We note that one type of combustion control, staged combustion air, and one type of post-combustion control, SNCR, are indicated as being compatible with all coal-fired unit types. Additional resources are available that document the availability of NO_X control equipment for industrial boilers.[324]

b. Oil-Fired Industrial Boilers

Most oil-fired boilers are fueled by either residual (heavy) oil or distillate (light) oil. The proposed NO_X emissions limit for residual oil-fired boilers subject to the requirements of this section is 0.2 lbs/mmBtu, and the proposed emissions limit for distillate oil-fired boilers is 0.12 lbs/mmBtu. The proposed averaging time for these emissions limits is a 30-day rolling average. As with coal-fired industrial boilers, a number of combustion and post-combustion NO_X control technologies exist that should enable most facilities to meet these emissions limits, and the Non-EGU Sectors TSD identifies numerous states that have already adopted emissions limits similar to the limits EPA proposes here. Table 2–3 of the ICI Boiler ACT indicates that two types of NO_X combustion control, low-NO_X burners and flue gas recirculation, are commonly found on oil-fueled industrial boilers, and that SNCR, a post-combustion control technology, is suitable to most oil-fueled industrial boilers other than those of the packaged firetube design. Some oil-fired industrial boilers may have already installed combustion or post-combustion control equipment to meet the emissions limits contained within EPA's NSPS at 40 CFR part 60 subpart Db, which requires that distillate oil-fired units meet a NO_X emissions limit of between 0.1 to 0.2 lbs/mmBtu depending on heat release rate, and that residual oil-fired units meet a NO_X emissions limit of between 0.3 to 0.4 lbs/mmBtu also depending on heat release rate.[325] The additional resources noted in the paragraph above discussing coal-fired industrial boilers also contain useful information regarding effective NO_X control equipment for residual and distillate fueled industrial boilers.

c. Gas-Fired Industrial Boilers

The proposed NO_X emissions limit for gas-fired boilers subject to the requirements of this section is 0.08 lbs/mmBtu. The proposed averaging time for these emissions limits is a 30-day rolling average.

As with fossil-fuel-fired boilers, numerous combustion and post-combustion NO_X control technologies exist that should enable most facilities to meet these emissions limits, and many states have already adopted emissions limits similar to the limits the EPA proposes here. Table 2–3 of the ICI Boiler ACT indicates the same control technologies that are suitable for application to oil-fired boilers are also likely to be effective at controlling NO_X emissions from gas-fired industrial boilers. Some gas-fired industrial boilers may have already installed combustion or post-combustion control equipment to meet the emissions limits contained within EPA's NSPS at 40 CFR 60 Subpart Db, which requires that gas-fired units meet a NO_X emissions limit of between 0.1 to 0.2 lbs/MMBtu depending on heat release rate. The additional resources noted in the discussion of coal-fired industrial boilers also contain useful information regarding effective NO_X control equipment for gas-fired industrial boilers.

The EPA anticipates that the majority of boilers covered by this section of the FIP will combust one of the fuels for which we have proposed emissions limits. However, we request comment on whether emissions limits for other types of fuels should be included in a final FIP, and if so, the types of fuels and the emissions limits that boilers powered by these fuels should be required to meet. Additionally, the EPA seeks comment on whether the EPA should establish less stringent emissions rates for boilers with low utilization rates, and if so, the appropriate emissions rate(s) and corresponding boiler utilization rate(s). The EPA also seeks comment on whether a different averaging time other than the 30-day averaging time proposed for boilers would be more appropriate and requests information supporting any suggested alternative.

Compliance Assurance Requirements

Given the similarities in the types of units covered, the EPA proposes that boilers subject to the requirements of this section demonstrate compliance in a manner similar to the emissions monitoring requirements found in section 60.45 of the NSPS for industrial, commercial, and institutional (ICI) boilers at 40 CFR part 60 subpart D. Those requirements include, among other provisions, the performance of an initial compliance test, installation of a CEMS unless the initial performance test indicates the unit's emissions rate is 70 percent or less of the required emissions rate, and an annual stack test for units not required to install a CEMS.

D. Submitting a SIP

A state may submit a SIP at any time to address CAA requirements that are covered by a FIP, and if the EPA approves the SIP it would replace the FIP, in whole or in part, as appropriate.[326] The EPA has established certain specialized provisions for replacing FIPs with SIPs within all the CSAPR trading programs, including the use of so-called ''abbreviated SIPs'' and ''full SIPs,'' *see* 40 CFR 52.38(a)(4) and (5) and (b)(4), (5), (8), (9), (11), and (12); 40 CFR 52.39(e), (f), (h), and (i). For a state to remove all FIP provisions through an approved SIP revision, a state would need to address all of the required reductions addressed by the FIP for that state, *i.e.,* reductions achieved through both EGU control and non-EGU control, as applicable to that state. Additionally, tribes in Indian country within the geographic scope of this proposed rule may elect to work with EPA under the Tribal Authority Rule to replace the FIP for areas of Indian country, in whole or in part, with a tribal implementation plan or

[322] 40 CFR 60.44b.

[323] ''Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (ICI) Boilers,'' EPA–453/R–94–022, March 1994.

[324] For example, see ''Applicability and Feasibility of NO_X, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional Boilers,'' Northeast States for Coordinated Air Use Management, November 2008 (revised January 2009) and ''Nitrogen Oxides (NO_x), Why and How They Are Controlled,'' EPA, Clean Air Technical Center, 456/F–99–006R, November 1999.

[325] 40 CFR 60.44b.

[326] CAA sections 110(c)(1)(B), 110(k)(3).

reasonably severable portions of a tribal implementation plan.

Under the proposed new FIPs for the 25 states whose EGUs would be required to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program with its proposed modifications, ''abbreviated'' and ''full'' SIP options continue to be available. An ''abbreviated SIP'' allows a state to submit a SIP revision that would establish state-determined allowance allocation provisions replacing the default FIP allocation provisions but leaves the remaining FIP provisions in place. A ''full SIP'' allows a state to adopt a trading program meeting certain requirements that would allow sources in the state to continue to use the EPA-administered trading program through an approved SIP revision, rather than a FIP. In addition, as under past CSAPR rulemakings, the EPA proposes to provide states with an opportunity to adopt state-determined allowance allocations for existing units for the second control period under this rule—in this case, the 2024 control period—through streamlined SIP revisions. *See* 76 FR 48326–48332 for additional discussion of full and abbreviated SIP options; *see also* 40 CFR 52.38(b).

1. SIP Option To Modify Allocations for 2024 Under EGU Trading Program

As with the start of past CSAPR rulemakings, the EPA proposes to allow a state to use a similar process to submit a SIP revision establishing allowance allocations for existing EGU units in the state for the second control period of the new requirements, *i.e.,* in 2024, to replace the EPA-determined default allocations. This proposed process would use updated deadlines, *i.e.,* a state must submit a letter to EPA within 60 days of publication of the final rule indicating its intent to submit a complete SIP revision by September 1, 2023. The SIP would provide in an EPA-prescribed format a list of existing units within the state and their allocations for the 2024 control period. If a state does not submit a letter of intent to submit a SIP revision, the EPA-determined default allocations will be recorded by 90 days of publication of the final rule. If a state submits a timely letter of intent but fails to submit a SIP revision, the EPA-determined default allocations will be recorded by September 15, 2023. If a state submits a timely letter of intent followed by a timely SIP revision that is approved, the approved SIP allocations will be recorded by March 1, 2024.

The EPA requests comment on the proposed option to modify allowance allocations under the Group 3 trading program for EGUs for the 2024 control period through a SIP revision.

2. SIP Option To Modify Allocations for 2025 and Beyond Under EGU Trading Program

For the 2025 control period and later, the EPA proposes that states in the CSAPR NO_X Ozone Season Group 3 Trading Program can modify the EPA-determined default allocations with an approved SIP revision. For the 2025 control period and later, SIPs can be full or abbreviated SIPs. States will also have the option to expand applicability to include EGUs between 15 MWe and 25 MWe or, in the case of states subject to the NO_X SIP Call, as discussed in Section VII.F.1 of this proposed rule, large non-EGU boilers and combustion turbines. Inclusion of the large non-EGUs would serve as a mechanism to address the state's outstanding regulatory obligations under the NO_X SIP Call with respect to those sources, and the state would be allowed to allocate a defined quantity of additional Group 3 allowances because of the expanded set of sources. *See* above and 76 FR 48326–48332 for additional discussion of full and abbreviated SIP options; *see also* 40 CFR 52.38(b).

For states that want to modify the EPA-determined default allocations or expand applicability of the EGU trading program, the EPA proposes that a state could submit a SIP revision that makes changes only to one or both of those type of provisions while relying on the FIP for the remaining provisions of the EGU trading program. This abbreviated SIP option allows states to tailor the FIP to their individual choices while maintaining the FIP-based structure of the trading program. In order to ensure the availability of allowance allocations for units in any Indian country within a state not covered by the state's CAA implementation planning authority, if the state chose to replace EPA's default allocations with state-determined allocations, the EPA would continue to administer any portion of each state emissions budget reserved as a new unit set-aside or an Indian country existing unit set-aside.

The proposed SIP submittal deadline for this type of revision is December 1, 2023, if the state intends for the SIP revision to be effective beginning with the 2025 control period. For states that submit this type of SIP revision, the EPA proposes that the deadline to submit state-determined allocations beginning with the 2025 control period under an approved SIP would be June 1, 2024, and the deadline for the EPA to record those allocations would be July 1, 2024. Similarly, under the proposed new deadlines a state could submit a SIP revision beginning with the 2026 control period and beyond by December 1, 2024, with state allocations for the 2026 control period due June 1, 2025, and the EPA recordation of the allocations by July 1, 2025.

The EPA requests comment on the proposed option to replace certain allowance allocation or applicability provisions under the Group 3 trading program for EGUs for control periods in 2025 and later years through a SIP revision.

3. SIP Option To Replace the Federal EGU Trading Program With an Integrated State EGU Trading Program

For the 2025 control period and later, the EPA proposes that states in the CSAPR NO_X Ozone Season Group 3 Trading Program can choose to replace the Federal EGU trading program with an integrated State EGU trading program through an approved SIP revision. Under this option, a state would submit a SIP revision that makes changes only to modify the EPA-determined default allocations or expand applicability of the EGU trading program and adopt identical provisions for the remaining portions of the EGU trading program. This SIP option allows states to replace these FIP provisions with state-based SIP provisions while continuing participation in the larger regional trading program. As with the abbreviated SIP option discussed above, in order to ensure the availability of allowance allocations for units in any Indian country within a state not covered by the state's CAA implementation planning authority, if the state chose to replace EPA's default allocations with state-determined allocations, EPA would continue to administer any portion of each state emissions budget reserved as a new unit set-aside or an Indian country existing unit set-aside.

Proposed deadlines for this type of SIP revision are the same as the deadlines for abbreviated SIP revisions. For the SIP-based program to start with the 2025 control period, the SIP deadline would be December 1, 2023, the deadline to submit state-determined allocations for the 2025 control period under an approved SIP would be June 1, 2024, and the deadline for the EPA to record those allocations would be July 1, 2024, and so on.

The EPA requests comment on the proposed option to replace the federal trading program for EGUs with an integrated state trading program for EGUs for control periods in 2025 and later years through a SIP revision.

4. SIP Revisions That Do Not Use the New Trading Program

States can submit SIP revisions to replace the FIP that achieve the necessary EGU emissions reductions but do not use the CSAPR NO_X Ozone Season Group 3 Trading Program. For a transport SIP revision that does not use the CSAPR NO_X Ozone Season Group 3 Trading Program, the EPA would evaluate the transport SIP based on the particular control strategies selected and whether the strategies as a whole provide adequate and enforceable provisions ensuring that the necessary emissions reductions (*i.e.,* reductions equal to or greater than what the Group 3 trading program will achieve) will be achieved. In order to address the applicable CAA requirements, the SIP revision should include the following general elements: (1) A comprehensive baseline 2023 statewide NO_X emissions inventory (which includes existing control requirements), which should be consistent with the 2023 emissions inventory that the EPA used to calculate the required state budget in this final proposed rule (unless the state can explain the discrepancy); (2) a list and description of control measures to satisfy the state emissions reduction obligation and a demonstration showing when each measure would be implemented to meet the 2023 and successive control periods; (3) fully-adopted state rules providing for such NO_X controls during the ozone season; (4) for EGUs greater than 25 MWe, monitoring and reporting under 40 CFR part 75, and for other units, monitoring and reporting procedures sufficient to demonstrate that sources are complying with the SIP (*see* 40 CFR part 51 subpart K (''source surveillance'' requirements)); and (5) a projected inventory demonstrating that state measures along with federal measures will achieve the necessary emissions reductions in time to meet the 2023 and successive compliance deadlines (*e.g.,* enforceable reductions commensurate with installation of SCR on coal-fired EGUs by the 2026 ozone season). The SIPs must meet procedural requirements under the Act, such as the requirements for public hearing, be adopted by the appropriate state board or authority, and establish by a practically enforceable regulation or permit(s) a schedule and date for each affected source or source category to achieve compliance. Once the state has made a SIP submission, the EPA will evaluate the submission(s) for completeness before acting on the SIP. EPA's criteria for determining completeness of a SIP submission are codified at 40 CFR part 51 appendix V.

For further information on replacing a FIP with a SIP, *see* the discussion in the final CSAPR rulemaking (76 FR 48326).

5. SIP Revision Requirements for Non-EGU Emissions Limits

EPA's promulgation of a non-EGU transport FIP would in no way affect the ability of states to submit, for review and approval, a SIP that replaces the requirements of the FIP with state requirements. In order to replace the non-EGU portion of the FIP in a state, the state's SIP must provide adequate provisions to prohibit an equivalent or greater amount of NO_X emissions that contribute significantly to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in any other state. The non-EGU requirements of the FIP would remain in place in each covered state until a state's SIP has been approved by the EPA to replace the FIP.

After promulgation of the final FIP, the EPA anticipates that the most straightforward method for a state to submit a SIP revision to replace the non-EGU portion of the FIP for the state would be to provide a SIP that includes emissions limits at an equivalent or greater level of stringency than is specified for non-EGU sources meeting the applicability criteria and associated compliance assurance provisions for each of the unit types identified in Section VII.C of this proposed rule.

The EPA seeks comment on other potential methods by which states could develop a SIP to obtain emissions reductions from non-EGU sources that would replace the state's non-EGU portion of the FIP. The EPA recognizes that states may select emissions reductions strategies that differ from the emissions limitations included in the proposed non-EGU FIP. But the state must still demonstrate that the replacement SIP provides an equivalent or greater amount of emissions reductions as the proposed FIP. The EPA anticipates that such emissions reductions strategies would have to achieve reductions beyond those emissions reductions already projected to occur in EPA's emissions projections and air quality modeling conducted at Steps 1 and 2. Such reductions must also be achieved on the same timeframe as the reductions that would be required in a final FIP. A demonstration of equivalency using other control strategies is complicated by the fact that the proposed emissions limits for non-EGU sources are generally rate-based and expressed in a variety of forms; this will make comparative analysis to determine equivalency challenging.

In all cases, a SIP submitted by a state to replace the non-EGU FIPs would need to rely on permanent and practically enforceable controls measures that are included in the SIP and, once approved by the EPA, rendered federally enforceable. So-called ''demonstration-only'' or ''non-regulatory'' SIPs would be insufficient. Further, the EPA anticipates that states would bear the burden of establishing that the state's alternative approach achieves at least an equivalent level of emissions reduction as the FIP, and (unless merely adopting directly the control requirements of the FIP) the state would need to provide a Step 3 multifactor analysis that the state's SIP eliminates significant contribution.

E. Title V Permitting

This proposed rule, like CSAPR, the CSAPR Update, and the Revised CSAPR Update does 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.[327] All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emissions limitations and other conditions as necessary to ensure compliance with the applicable requirements of the CAA, including the requirements of the applicable SIP. CAA sections 502(a) and 504(a), 42 U.S.C. 7661a(a) and 7661c(a). The ''applicable requirements'' that must be addressed in title V permits are defined in the title V regulations (40 CFR 70.2 and 71.2 (definition of ''applicable requirement'')).

The EPA anticipates that, given the nature of the units subject to this proposed rule, most if not all of the sources at which the units are located are already subject to title V permitting requirements. For sources subject to title V, the interstate transport requirements for the 2015 ozone NAAQS that are applicable to them under the new or amended FIPs would be ''applicable requirements'' under title V and therefore must be addressed in the title V permits. For example, requirements concerning designated representatives, monitoring, reporting, and recordkeeping, the requirement to hold allowances covering emissions, the compliance assurance provisions, and liability are ''applicable requirements'' that must be addressed in the permits.

Title V of the CAA establishes the basic requirements for state title V

[327] Part 70 addresses requirements for state title V programs, and Part 71 governs the federal title V program.

permitting programs, including, among other things, provisions governing permit applications, permit content, and permit revisions that address applicable requirements under final FIPs in a manner that provides the flexibility necessary to implement market-based programs such as the trading programs established in CSAPR, the CSAPR Update, the Revised CSAPR Update and this proposed rule. 42 U.S.C. 7661a(b); 40 CFR 70.6(a)(8) & (10); 40 CFR 71.6(a)(8) & (10).

In CSAPR, the CSAPR Update and the Revised CSAPR Update, the EPA established standard requirements governing how sources covered by that rule would comply with title V and its regulations.[328] 40 CFR 97.506(d), 97.806(d) and 97.1006(d). For any new or existing sources subject to this proposed rule, identical title V compliance provisions would apply, just as they would have in the CSAPR NO_X Ozone Season Group 3 Trading Program. For example, the title V regulations provide that a permit issued under title V must include ''[a] provision stating that no permit revision shall be required under any approved . . . emissions trading and other similar programs or processes for changes that are provided for in the permit.'' 40 CFR 70.6(a)(8) and 71.6(a)(8). Consistent with these provisions in the title V regulations, in CSAPR, the CSAPR Update and the Revised CSAPR Update, the EPA included a provision stating that no permit revision is necessary for the allocation, holding, deduction, or transfer of allowances. 40 CFR 97.506(d)(1), 97.806(d)(1) and 97.1006(d)(1). This provision is also included in each title V permit for an affected source. This proposed rule maintains the approach taken under CSAPR, the CSAPR Update and the Revised CSAPR Update that allows allowances to be traded (or allocated, held, or deducted) without a revision to the title V permit of any of the sources involved.

Similarly, this proposed rule would also continue to support the means by which a source in the proposed trading program can use the title V minor modification procedure to change its approach for monitoring and reporting emissions, in certain circumstances. Specifically, sources may use the minor modification procedure so long as the new monitoring and reporting approach is one of the prior-approved approaches under CSAPR, the CSAPR Update and the Revised CSAPR Update (*i.e.,* approaches using a continuous emissions monitoring system under subparts B and H of part 75, an excepted monitoring system under appendices D and E to part 75, a low mass emissions excepted monitoring methodology under 40 CFR 75.19, or an alternative monitoring system under subpart E of part 75), and the permit already includes a description of the new monitoring and reporting approach to be used. *See* 40 CFR 97.506(d)(2), 97.806(d)(2) and 97.1006(d)(2); 40 CFR 70.7(e)(2)(i)(B) and 40 CFR 71.7(e)(1)(i)(B). As described in EPA's 2015 Title V Guidance, sources may comply with this requirement by including a table of all of the approved monitoring and reporting approaches under CSAPR, the CSAPR Update and the Revised CSAPR Update trading programs in which the source is required to participate, and the applicable requirements governing each of those approaches.[329] Inclusion of such a table in a source's title V permit therefore allows a covered unit that seeks to change or add to its chosen monitoring and recordkeeping approach to easily comply with the regulations governing the use of the title V minor modification procedure.

Under CSAPR, the CSAPR Update and the Revised CSAPR Update, in order to employ a monitoring or reporting approach different from the prior-approved approaches discussed previously, unit owners and operators must submit monitoring system certification applications to the EPA establishing the monitoring and reporting approach actually to be used by the unit, or, if the owners and operators choose to employ an alternative monitoring system, to submit petitions for that alternative to the EPA. These applications and petitions are subject to the EPA review and approval to ensure consistency in monitoring and reporting among all trading program participants. EPA's responses to any petitions for alternative monitoring systems or for alternatives to specific monitoring or reporting requirements are posted on EPA's website.[330] The EPA maintains the same approach in this proposed rule.

Consistent with EPA's approach under CSAPR, the CSAPR Update and the Revised CSAPR Update, the applicable requirements resulting from the new and amended FIPs generally will have to be incorporated into affected sources' existing title V permits either pursuant to the provisions for reopening for cause (40 CFR 70.7(f) and 71.7(f)) or the standard permit renewal provisions (40 CFR 70.7(c) and 71.7(c)).[331] For sources newly subject to title V that are affected sources under the FIPs, the initial title V permit issued pursuant to 40 CFR 70.7(a) should address the final FIP requirements.

As was the case in the CSAPR, the CSAPR Update and the Revised CSAPR Update, the new and amended FIPs impose no independent permitting requirements and the title V permitting process will impose no additional burden on sources already required to be permitted under title V.

F. Relationship to Other Emissions Trading and Ozone Transport Programs

1. NO_X SIP Call

States affected by both the NO_X SIP Call for the 1979 ozone NAAQS and any final ozone season requirements established upon finalization of this proposed rule for the 2015 ozone NAAQS will be required to comply with the requirements of both rules. EPA is proposing to require NO_X ozone season emissions reductions from EGUs larger than 25 MWe in many of the NO_X SIP Call states, and at greater stringency than required by the NO_X SIP Call, by requiring the EGUs to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program. Therefore, this proposed rule, if finalized, would satisfy the requirements of the NO_X SIP Call for these large EGUs.

In the Revised CSAPR Update, the EPA finalized the option for any NO_X SIP Call state that was also subject to the Revised CSAPR Update to voluntarily submit a SIP revision to expand the applicability of the Group 3 trading program to include all NO_X Budget Trading Program units, which in addition to large EGUs also include large non-EGU boilers and combustion turbines with a maximum design heat input greater than 250 mmBtu/hr. As part of such a SIP revision, the state

[328] The EPA has also issued a guidance document and template that includes instructions for how to incorporate the applicable requirements into a source's Title V permit. *See* Memorandum dated May 13, 2015, from Anna Marie Wood, Director, Air Quality Policy Division, and Reid P. Harvey, Director, Clean Air Market Division, EPA, to Regional Air Division Directors, Subject: ''Title V Permit Guidance and Template for the Cross-State Air Pollution Rule'' (''2015 Title V Guidance''), available at *https://www.epa.gov/sites/default/files/2016-10/documents/csapr_title_v_permit_guidance.pdf.*

[329] Id.

[330] *https://www.epa.gov/airmarkets/part-75-petition-responses.*

[331] A permit is reopened for cause if any new applicable requirements (such as those under a FIP) become applicable to an affected 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).

would be allowed to issue additional emissions allowances capped at a level intended to preserve the stringency of the Group 3 trading program. In today's proposed rule, the EPA is not proposing any changes to this provision of the Group 3 trading program.[332]

2. Acid Rain Program

This proposed rule, if finalized, would not affect any Acid Rain Program requirements. Any Title IV sources that are subject to provisions of this proposed rule would still need to continue to comply with all Acid Rain provisions. Acid Rain Program SO_2 and NO_X requirements are established independently in Title IV of the CAA and will continue to apply independently of this proposed rule's provisions. Acid Rain sources will still be required to comply with Title IV requirements, including the requirement to hold Title IV allowances to cover SO_2 emissions after the end of a compliance year.

3. Other Current Emissions Trading Programs

This proposed rule, if finalized, would not substantively affect any provisions of the CSAPR NO_X Annual, CSAPR SO_2 Group 1, CSAPR SO_2 Group 2, CSAPR NO_X Ozone Season Group 1, or CSAPR NO_X Ozone Season Group 2 trading programs for sources that continue to participate in those programs except with regard to the schedule for EPA to record certain allowance allocations, as discussed in Section VII.B.12 of this proposed rule. In addition, certain revisions are proposed to the CSAPR NO_X Ozone Season Group 2 Trading Program regulations to address the proposed transition of sources in eight states from that program to the CSAPR NO_X Ozone Season Group 3 Trading Program, as discussed in Section VII.B.11 of this proposed rule. Sources that are subject to any of the CSAPR trading programs will still be required to comply with all requirements, including the requirement to hold allowances to cover emissions after the end of a control period.

[332] In the CSAPR Update, the EPA finalized an identical option allowing NO_X SIP Call states to expand applicability of the Group 2 trading program to cover certain non-EGUs. If the geographic expansion of the Group 3 trading program proposed in this rulemaking is finalized as proposed, no NO_X SIP Call states would continue to be covered by the Group 2 trading program. Because the provision allowing NO_X SIP Call states to expand applicability of the Group 2 trading program to include such non-EGUs would therefore be obsolete, the EPA is proposing to remove the provision.

VIII. Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement

Consistent with EPA's commitment to integrating environmental justice in the agency's actions, and following the directives set forth in multiple Executive Orders, the Agency has analyzed the impacts of this proposed rule on communities with environmental justice concerns and engaged with stakeholders representing these communities to seek input and feedback. Executive Order 12898 is discussed in Section XI.J of this proposed rule and analytical results are available in Chapter 7 of the RIA.

A. Introduction

Executive Order 12898 directs EPA staff to identify the populations of concern who are most likely to experience unequal burdens from environmental harms; specifically, minority populations, low-income populations, and indigenous peoples.[333] Additionally, Executive Order 13985 is intended to advance racial equity and support underserved communities through federal government actions.[334] The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. EPA further defines the term fair treatment to mean that ''no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies.'' [335] In recognizing that minority and low-income populations often bear an unequal burden of environmental harms and risks, EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution.

B. Analytical Considerations

EPA's environmental justice technical guidance [336] states that ''[t]he analysis of potential EJ concerns for regulatory actions should address three questions:

1. Are there potential environmental justice concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline?

2. Are there potential environmental justice concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration?

3. For the regulatory option(s) under consideration, are potential environmental justice concerns created or mitigated compared to the baseline?''

[333] 59 FR 7629, February 16, 1994.

[334] 86 FR 7009, January 20, 2021.

[335] *https://www.epa.gov/environmentaljustice.*

[336] U.S. Environmental Protection Agency (EPA), 2015. Guidance on Considering Environmental Justice During the Development of Regulatory Actions.

To address these questions in EPA's first quantitative EJ analysis in the context of a transport rule, the EPA developed a unique analytical approach that considers the purpose and specifics of the proposed rulemaking, as well as the nature of known and potential exposures and impacts. However, due to data limitations, it is possible that our analysis failed to identify disparities that may exist, such as potential environmental justice characteristics (*e.g.,* unemployed), environmental impacts (*e.g.,* other ozone metrics), and more granular spatial resolutions (*e.g.,* neighborhood scale) that were not evaluated.

For the proposed rule, we employ two types of analytics to respond to the above three questions: Proximity analyses and exposure analyses. Both types of analyses can inform whether there are potential EJ concerns for population groups of concern in the baseline (question 1).[337] In contrast, only the exposure analyses, which are based on future air quality modeling, can inform whether there will be potential EJ concerns after implementation of the regulatory options under consideration (question 2) and whether potential EJ concerns will be created or mitigated compared to the baseline (question 3). While the exposure analysis can respond to all three questions, it should be noted that exposure is limited to a single ozone metric, the maximum daily 8-hour average, averaged across the April through September warm season (AS–MO3). This ozone metric likely smooths potential daily ozone gradients and is not directly relatable to the National Ambient Air Quality Standard (NAAQS). Additionally, the ozone exposure analytic results are provided in two formats: Aggregated and distributional. The aggregated results provide an overview of potential ozone exposure differences across populations at the national- and state-levels, while the distributional results show detailed

[337] The baseline for proximity analyses is current population information (*e.g.,* 2021), whereas the baseline for ozone exposure analyses are the future years in which the regulatory options will be implemented (*e.g.,* 2023 and 2026).

information about ozone concentrations experienced by everyone within each population.

In Chapter 7 of the RIA we utilize the two types of analytics to address the three EJ questions by quantitatively evaluating (1) the proximity of affected facilities to potentially disadvantaged populations (Section 7.3.1), (2) the potential for disproportionate total ozone concentrations in the baseline across different demographic groups (Sections 7.4.1.1 and 7.4.2.1), and (3) how regulatory alternatives differentially impact the ozone concentration changes experienced by different demographic populations (Sections 7.4.1.2 and 7.4.2.2). Each of these analyses depends on mutually exclusive assumptions, was performed to answer separate questions, and is associated with unique limitations and uncertainties.

Baseline demographic proximity analyses can be relevant for identifying populations that may be exposed to local pollutants, such as NO_2 emitted from affected sources in this proposed rule. However, such analyses are less useful here as they do not account for the potential impacts of this proposed rule on long-range ozone concentration changes. The baseline demographic proximity analysis presented in the RIA finds larger percentages of Hispanic individuals, Black individuals, people below the poverty level, people with less educational attainment, and people linguistically isolated living within 5 km and 10 km of an affected EGU, compared to national averages. It also finds larger percentages of people below the poverty level and with less educational attainment living within 5 km and 10 km of an affected non-EGU. Separately, the tribal proximity analysis finds multiple tribes and unique tribal lands located within 50 miles of an affected facility. These results do not in themselves demonstrate disproportionate impacts of affected facilities in the baseline but could suggest that emission reductions from this proposed rule may be responsive to potential local air quality concerns of nearby communities.

Whereas the proximity analyses are limited to evaluating local pollutants under baseline scenarios (question 1), the ozone exposure analyses can provide insight into all three EJ questions with regard to AS–MO3 concentrations. Even though both the proximity and ozone exposure analyses can improve understanding of baseline EJ concerns (question 1), the two should not be directly compared. This is because the demographic proximity analysis does not include air quality information and is based on current, not future, population information.

Importantly, the baseline analysis of AS–MO3 ozone concentrations responds to question 1 from EPA's environmental justice technical guidance document more directly than the proximity analyses, as it evaluates a form of the environmental stressor targeted by the regulatory action. Baseline AS–MO3 analyses show that certain populations, such as American Indians, Hispanics, and Asians, may experience somewhat higher AS–MO3 concentrations compared to the national average. The less educated and children may also experience higher concentrations compared to the national average, but to a lesser extent. Conversely, Black populations may experience lower AS–MO3 concentrations than the national average. Therefore, also in response to question 1, there likely are potential environmental justice concerns associated with ozone exposures affected by the regulatory action for population groups of concern in the baseline. However, these baseline exposure results have not been fully explored and additional analyses are likely needed to understand potential implications.

The ozone exposure analysis evaluates the impacts of the proposed rule on future ozone concentrations after rule implementation. When comparing across the policy, more-, and less-stringent regulatory alternatives, AS–MO3 concentrations are reduced across all populations evaluated in both future years and across both EGUs and non-EGUs. In other words, we expect that populations experiencing disproportionate AS–MO3 exposures in the baseline will experience similar disproportionate AS–MO3 exposures under the proposed rulemaking, although to a lesser absolute extent as the action described in this proposed rule is expected to lower ozone in many areas, including residual ozone nonattainment areas, and thus alleviate some pre-existing health risks of ozone across all populations evaluated. Therefore, in response to question 2, we expect that there will be potential EJ concerns with regard to AS–MO3 concentrations after implementation of the regulatory options under consideration.

Question 3 asks whether potential EJ concerns will be created or mitigated as compared to the baseline. As the RIA estimates disproportionate AS–MO3 exposures in the baseline and similar reductions in all population evaluated, we do not predict that potential EJ concerns related to AS–MO3 concentrations will be created or mitigated as compared to the baseline (question 3).

The ozone exposure results should not be extrapolated to ozone metrics other than AS–MO3. Detailed environmental justice analytical results can be found in Chapter 7 of the RIA.

C. Outreach and Engagement

Prior to this proposed rule, EPA initiated a public outreach effort to gather input from stakeholder groups likely to be interested in this proposed rule. Specifically, the EPA hosted an environmental justice webinar on October 26, 2021, to share information about the proposed rule and solicit feedback about potential environmental justice considerations. The webinar was attended by over 180 individuals representing state governments, federally recognized tribes, environmental NGOs, higher education institutions, industry, and the EPA.[338] Participants were invited to comment during the webinar or provide written comments to a pre-regulatory docket. The webinar was recorded and distributed to attendees after the event. Some of the key issues raised by stakeholders during the webinar and in the pre-proposal comments are described below.

Daily emissions rate limits. Several commenters asserted that cap and trade programs with seasonal limits on overall NO_X emissions do not prevent facilities from running their controls inefficiently on high ozone days. These commenters recommended that facilities linked to downwind ozone problems comply with daily rate limits to ensure that emissions reductions occur on days when ozone is highest. The commenters noted that daily limits could particularly benefit environmental justice communities located near facilities and would also benefit those located downwind.

Regulation of other sources. Several commenters asserted that the EPA should consider regulation of sources other than EGUs and sources of NO_X in rulemakings pertaining to issues of ozone transport. For example, some commenters asserted that the EPA should regulate emissions from non-EGUs, mobile sources, and sources of VOCs.

Environmental justice analysis and methodology in rulemakings. Several commenters offered recommendations to improve environmental justice analysis and methodology in rulemakings that address air pollution.

[338] This does not constitute EPA's tribal consultation under E.O. 13175, which is described in Section XI.F of this proposed rule.

One commenter recommended that the EPA should broadly: (1) Identify communities of interest, based on the number of and proximity to polluting facilities; (2) integrate demographic factors to discern social, economic, and racial disparities in these areas; (3) consider the community's particular vulnerabilities and sensitivities to health harms and risks, and exposure to cumulative health harms and risks; and (4) reach out to the community members near such facilities themselves to gain tangible, lived experiences across their lifetimes. The commenter also suggested that the EPA should build off factors identified in existing environmental justice screening tools, including EPA EJSCREEN and California's CalEnviroScreen. One commenter noted that in developing environmental justice analyses, the EPA should consider and address the need for regulatory certainty, including the need for clear regulatory definitions of environmental justice areas and clear requirements for those areas.

Environmental justice stakeholder outreach in rulemakings. Some commenters asserted that the EPA could improve stakeholder outreach in the rulemaking process. For example, one commenter noted that during the development of a rule proposal, the EPA could more directly reach out to all potentially impacted environmental justice communities, be more prepared to answer questions about the rule proposal, and be more aware of holidays when establishing comment periods.

Additionally, some comments touched on issues that are also relevant to other EPA policies and programs. For example, some commenters asserted that the EPA should base air pollutant transport policy more on monitored data rather than modeling data to promptly address air pollution in areas where current monitoring data indicates an exceedance of the NAAQS. Other commenters recommended that the EPA consider strengthening cost thresholds for Reasonably Available Control Technology (RACT), a program that is applicable to certain existing sources in non-attainment areas.

In addition to the engagement conducted prior to this proposed rule, EPA is providing the public, including those communities disproportionately impacted by the burdens of pollution, opportunities to engage in the EPA's public comment period for this proposed rule, including by hosting a public hearing. This public hearing will occur according to the schedule identified in the Public Participation section of this proposed rule.

IX. Costs, Benefits, and Other Impacts of the Proposed Rule

In the Regulatory Impact Analysis for the proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (RIA), EPA estimated the benefits, compliance costs, and emissions changes that may result from the proposed rule for the analysis period 2023 to 2042. The estimated benefits and compliance costs are presented in detail in the RIA accompanying this proposed rule. EPA notes that for EGUs the estimated benefits and compliance costs are directly associated with generation shifting to minimize costs; fully operating existing SCRs during ozone season; fully operating existing SNCRs during ozone season; installing state-of-the-art combustion controls; imposing backstop emission rate limits on certain units that lack SCR controls; and unit-level decisions to retrofit or retire. EPA also notes that for non-EGUs the estimated benefits and compliance costs are directly associated with installing controls to meet the NO_X emissions limits presented in Section I.B above.

For EGUs, EPA analyzed this proposed rule's emission budgets using uniform control stringency represented by $1,800 per ton of NO_X (2016$) in 2023 and $11,000 per ton of NO_X (2016$) in 2026. EPA also analyzed a more and a less stringent alternative. The more and less stringent alternatives differ from the proposed rule in that they set different NO_X ozone season emission budgets for the affected EGUs and different dates for compliance with backstop emission rate limits.

For non-EGUs, EPA analyzed this proposed rule using a marginal cost threshold of up to $7,500 per ton (2016$) for 2026 for the following emissions units and industries: Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; and high-emitting boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills. The less stringent alternative assumes there are emissions limits for all emission units from the proposal except for high-emitting boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills. The more stringent alternative assumes emissions limits for all emission units from the proposed rule and all boilers, not just high-emitting boilers, in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.

Table IX–1 provides the projected 2023 through 2027, 2030, 2035, and 2042 EGU emission reductions for the evaluated regulatory control alternatives. For additional information on emissions changes, *see* Table 4.6 and Table 4–7 in Chapter 4 of the RIA.

TABLE IX–1—EGU OZONE SEASON NO_X EMISSIONS CHANGES AND ANNUAL EMISSIONS REDUCTIONS (TONS) FOR NO_X, SO_2, $PM_{2.5}$, AND CO_2 FOR THE REGULATORY CONTROL ALTERNATIVES FROM 2023–2042

	Proposed rule	Less stringent alternative	More stringent alternative
2023:			
NO_X (ozone season)	6,000	6,000	7,000
NO_X (annual)	10,000	10,000	10,000
SO_2 (annual) *		1,000	2,000
CO_2 (annual, thousand metric)			
$PM_{2.5}$ (annual)			
2024:			
NO_X (ozone season)	26,000	14,000	29,000
NO_X (annual)	42,000	22,000	45,000
SO_2 (annual)	42,000	20,000	43,000
CO_2 (annual, thousand metric)	18,000	10,000	19,000
$PM_{2.5}$ (annual)	4,000	1,000	4,000
2025:			

TABLE IX–1—EGU OZONE SEASON NO_X EMISSIONS CHANGES AND ANNUAL EMISSIONS REDUCTIONS (TONS) FOR NO_X, SO_2, $PM_{2.5}$, AND CO_2 FOR THE REGULATORY CONTROL ALTERNATIVES FROM 2023–2042—Continued

	Proposed rule	Less stringent alternative	More stringent alternative
NO_X (ozone season)	46,000	22,000	51,000
NO_X (annual)	73,000	33,000	80,000
SO_2 (annual)	83,000	39,000	84,000
CO_2 (annual, thousand metric)	37,000	19,000	38,000
$PM_{2.5}$ (annual)	9,000	2,000	9,000
2026:			
NO_X (ozone season)	47,000	32,000	53,000
NO_X (annual)	81,000	55,000	87,000
SO_2 (annual)	106,000	76,000	108,000
CO_2 (annual, thousand metric)	40,000	26,000	42,000
$PM_{2.5}$ (annual)	9,000	5,000	9,000
2027:			
NO_X (ozone season)	49,000	42,000	54,000
NO_X (annual)	88,000	76,000	95,000
SO_2 (annual)	129,000	113,000	131,000
CO_2 (annual, thousand metric)	43,000	34,000	46,000
$PM_{2.5}$ (annual)	10,000	7,000	10,000
2030:			
NO_X (ozone season)	52,000	52,000	57,000
NO_X (annual)	96,000	98,000	100,000
SO_2 (annual)	104,000	100,000	103,000
CO_2 (annual, thousand metric)	50,000	45,000	50,000
$PM_{2.5}$ (annual)	9,000	9,000	9,000
2035:			
NO_X (ozone season)	49,000	50,000	52,000
NO_X (annual)	90,000	93,000	93,000
SO_2 (annual)	96,000	93,000	98,000
CO_2 (annual, thousand metric)	38,000	36,000	38,000
$PM_{2.5}$ (annual)	11,000	12,000	10,000
2042:			
NO_X (ozone season)	47,000	47,000	48,000
NO_X (annual)	70,000	75,000	71,000
SO_2 (annual)	54,000	50,000	54,000
CO_2 (annual, thousand metric)	25,000	23,000	24,000
$PM_{2.5}$ (annual)	8,000	9,000	8,000

*SO_2 emissions reductions under the proposed rule are 350 tons and rounded to zero. SO_2 emissions reductions under the less stringent alternative are 507 tons and rounded to 1,000 tons. SO_2 emissions reductions are 1,699 tons under the more stringent alternative and rounded to 2,000 tons. Given the rounding, the difference between the reductions under the proposed rule and the less stringent alternative is approximately 160 tons.

Table IX–2 below provides a summary of the ozone season emissions for non-EGUs for the 23 states subject to the proposed non-EGU emissions limits starting in 2026, along with the estimated ozone season reductions for 2026 for the proposed rule and the less and more stringent alternatives. The analysis in the RIA assumes that the estimated reductions in 2026 will be the same in later years.

TABLE IX–2—OZONE SEASON (OS) NO_X EMISSIONS AND EMISSIONS REDUCTIONS (TONS) FOR NON-EGUS FOR THE PROPOSED RULE AND THE LESS AND MORE STRINGENT ALTERNATIVES *

State	2019 OS NO_X emissions [a]	Proposed rule—OS NO_X reductions	Less stringent alternative—OS NO_X reductions	More stringent alternative—OS NO_X reductions
AR	8,265	1,654	922	1,654
CA	14,579	1,666	1,598	1,777
IL	16,870	2,452	2,452	2,553
IN	19,604	3,175	2,787	3,175
KY	11,934	2,291	2,291	2,291
LA	35,831	6,769	4,121	6,955
MD	2,365	45	45	45
MI	18,996	2,731	2,731	3,093
MN	17,591	673	673	789
MO	9,109	3,103	3,103	3,103
MS	12,284	1,761	1,577	1,761
NJ	2,025	0	0	29
NV	2,418	0	0	0
NY	6,003	500	389	613
OH	19,729	2,790	2,611	2,814
OK	22,146	3,575	3,575	3,871

TABLE IX–2—OZONE SEASON (OS) NO_X EMISSIONS AND EMISSIONS REDUCTIONS (TONS) FOR NON-EGUS FOR THE PROPOSED RULE AND THE LESS AND MORE STRINGENT ALTERNATIVES *—Continued

State	2019 OS NO_X emissions [a]	Proposed rule—OS NO_X reductions	Less stringent alternative—OS NO_X reductions	More stringent alternative—OS NO_X reductions
PA	15,861	3,284	3,132	3,340
TX	47,135	4,440	4,440	6,596
UT	6,276	757	757	757
VA	7,041	1,563	1,465	1,660
WI	6,571	2,150	677	2,234
WV	9,825	982	982	982
WY	10,335	826	826	826
Totals	322,793	47,186	41,153	50,918

* In the non-EGU screening assessment for 2026, EPA estimated emissions reduction potential from the non-EGU industries and emissions units. In the screening assessment, EPA used CoST to identify emissions units, emissions reductions, and associated compliance costs to evaluate the effects of potential non-EGU emissions control measures and technologies. CoST is designed to be used for illustrative control strategy analyses (*e.g.,* NAAQS regulatory impact analyses) and not for unit-specific, detailed engineering analyses. The estimates from CoST identify proxies for (1) non-EGU emissions units that have emissions reduction potential, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units. The control cost estimates do not include monitoring, recordkeeping, reporting, or testing costs. This screening assessment is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that fully evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs.

[a] EPA determined that the 2019 inventory was appropriate because it provided a more accurate prediction of potential near-term emissions reductions. The analysis in the RIA assumes that the 2019 ozone season emissions will be the same in 2026 and later years.

For EGUs, the EPA analyzed ozone season NO_X emission reductions and the associated costs to the power sector using the Integrated Planning Model (IPM) and its underlying data and inputs. For non-EGUs, the EPA analyzed ozone season NO_X emission reductions and the associated costs for 2026 in the Non-EGU Screening Assessment memorandum. Table IX–3 reflects the estimates of the changes in the cost of supplying electricity for the regulatory control alternatives for EGUs and estimates of complying with the emissions limits for non-EGUs. For EGUs, compliance costs are negative in 2023. While seemingly counterintuitive, estimating negative compliance costs in a single year is possible given IPM's objective function is to minimize the discounted net present value (NPV) of a stream of annual total cost of generation over a multi-decadal time period. As such the model may undertake a compliance pathway that pushes higher costs later into the forecast period, since future costs are discounted more heavily than near term costs. This can result in a policy scenario showing single year costs that are lower than the Baseline, but over the entire forecast horizon, the policy scenario shows higher costs. For a detailed description of these cost trends, please see Chapter 4, Section 4.5.2 of the RIA. For a detailed description of the methods and results from Non-EGU Screening Assessment memorandum, see Chapter 4, Sections 4.4 and 4.5.2 of the RIA.

TABLE IX–3—TOTAL ESTIMATED COMPLIANCE COSTS (MILLION 2016$), 2023–2042

	Proposed rule	Less-stringent alternative	More-stringent alternative
2023:			
EGUs	−209	−173	−178
Non-EGUs	....	....	....
Total	−209	−173	−178
2026:			
EGUs	707	−406	1,180
Non-EGUs	411	357	445
Total	1,117	−49	1,625
2027:			
EGUs	1,544	1,540	1,983
Non-EGUs	411	357	445
Total	1,955	1,896	2,428
2030:			
EGUs	1,235	1,200	1,740
Non-EGUs	411	357	445
Total	1,646	1,557	2,185
2035:			
EGUs	1,729	1,596	2,335
Non-EGUs	411	357	445
Total	2,139	1,953	2,780
2042:			
EGUs	910	1,757	1,001
Non-EGUs	411	357	445
Total	1,321	2,114	1,446

Tables IX–4 and IX–5 report the estimated economic value of avoided premature deaths and illness in each year relative to the baseline along with the 95% confidence interval. In each of these tables, for each discount rate and regulatory control alternative, multiple benefits estimates are presented reflecting alternative ozone and $PM_{2.5}$ mortality risk estimates. For additional information on these benefits, see Chapter 5 of the RIA.

TABLE IX–4—ESTIMATED DISCOUNTED ECONOMIC VALUE OF AVOIDED OZONE AND $PM_{2.5}$-ATTRIBUTABLE PREMATURE MORTALITY AND ILLNESS FOR THE PROPOSED POLICY SCENARIOS IN 2023

[95% Confidence interval; millions of 2016$] [a] [b]

Disc. rate	Pollutant	Proposal	More stringent alternative	Less stringent alternative
3%	Ozone Benefits	$57 ($15 to $120) [c] *and* $460 ($51 to $1,200) [d].	$65 ($17 to $140) [c] *and* $530 ($59 to $1,400) [d].	$57 ($15 to $120) [c] *and* $460 ($51 to $1,200). [d]
	PM Benefit Per Ton (BPT)s.	$44 *and* $45	$190 *and* $190	$59 *and* $60.
	Ozone Benefits plus PM BPTs.	$100 ($59 to $160) [c] *and* $500 ($96 to $1,200) [d].	$250 ($200 to $330) [c] *and* $720 ($250 to $1,600) [d].	$120 ($74 to $180) [c] *and* $520 ($110 to $1,300). [d]
7%	Ozone Benefits	$51 ($9.6 to 110) [c] *and* $410 ($42 to $1,100) [d].	$58 ($11 to $130) [c] *and* $480 ($49 to $1,300) [d].	$51 ($9.6 to $110) [c] *and* $410 ($42 to $1,100). [d]
	PM BPTs	$40 *and* $41	$170 *and* $170	$53 *and* $54.
	Ozone Benefits plus PM BPTs.	$90 ($49 to $150) [c] *and* $450 ($83 to $1,100) [d].	$230 ($180 to $300) [c] *and* $650 ($220 to $1,400) [d].	$100 ($63 to $170) [c] *and* $470 ($97 to $1,100). [d]

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated ozone benefits for changes in NO_X for the ozone season and changes in $PM_{2.5}$ and $PM_{2.5}$ precursors for EGUs in 2023. This table does not include benefits from reductions for non-EGUs because reductions from these sources are not expected prior to 2026 when the proposed standards would become effective.
[c] Using the pooled short-term ozone exposure mortality risk estimate.
[d] Using the long-term ozone exposure mortality risk estimate.

TABLE IX–5—ESTIMATED DISCOUNTED ECONOMIC VALUE OF AVOIDED OZONE AND $PM_{2.5}$-ATTRIBUTABLE PREMATURE MORTALITY AND ILLNESS FOR THE PROPOSED POLICY SCENARIO IN 2026

[95% Confidence interval; millions of 2016$] [a] [b]

Disc. rate	Pollutant	Proposal	More stringent alternative	Less stringent alternative
3%	Ozone Benefits	$1,200 ($310 to $2,600) [c] *and* $10,000 ($1,100 to $26,000) [d].	$1,300 (340 to $2,900) [c] *and* $11,000 ($1,200 to $29,000) [d].	$830 ($210 to $1,800) [c] *and* $6,900 ($760 to $18,000). [d]
	PM BPTs	$8,100 *and* $8,300	$7,800 *and* $7,900	$3,400 *and* $3,500.
	Ozone Benefits plus PM BPTs.	$9,300 ($8,400 to $11,000) [c] *and* $18,000 ($9,400 to $35,000) [d].	$9,100 ($8,100 to $11,000) [c] *and* $19,000 ($9,200 to $37,000) [d].	$4,300 ($3,700 to $5,200) [c] *and* $10,000 ($4,300 to $22,000). [d]
7%	Ozone Benefits	$1,100 ($200 to $2,400) [c] *and* $9,000 ($920 to $24,000) [d].	$1,200 ($220 to $2,700) [c] *and* $10,000 ($1,000 to $26,000) [d].	$740 ($140 to $1,700) [c] *and* $6,200 ($630 to $16,000). [d]
	PM BPTs	$7,300 *and* $7,400	$7,000 *and* $7,100	$3,100 *and* $3,200.
	Ozone Benefits plus PM BPTs.	$8,400 ($7,500 to $9,700) [c] *and* $16,000 ($8,300 to $31,000) [d].	$8,200 ($7,200 to $9,700) [c] *and* $17,000 ($8,200 to $34,000) [d].	$3,800 ($3,200 to $4,800) [c] *and* $9,300 ($3,800 to $19,000). [d]

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated changes in NO_X for the ozone season and changes in $PM_{2.5}$ and $PM_{2.5}$ precursors in 2026. This table represents changes in EGU and non-EGU ozone season and annual controls.
[c] Sum of ozone mortality estimated using the pooled short-term ozone exposure risk estimate and the Di et al. (2017) long-term $PM_{2.5}$ exposure mortality risk estimate.
[d] Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Di et al. (2017) long-term $PM_{2.5}$ exposure mortality risk estimate.

In Tables IX–6, IX–7, and IX–8, EPA presents a summary of the monetized benefits, costs, and net benefits of the proposal and the more and less stringent alternatives for 2023, 2026, and 2030, respectively. The monetized benefits estimates do not include important climate benefits that were not monetized in the RIA. In addition, there are important water quality benefits and health benefits associated with reductions in concentrations of air pollutants other than $PM_{2.5}$ and ozone that are not quantified. We request comment on how to address the climate benefits and other categories of non-monetized benefits of the proposed rule. Discussion of the non-monetized health, climate, welfare, and water quality benefits is found in Chapter 5 of the RIA.

TABLE IX–6—MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE PROPOSED AND LESS AND MORE STRINGENT ALTERNATIVES FOR 2023 FOR THE U.S.

[Millions of 2016$] [a] [b]

	Proposed rule	Less stringent alternative	More stringent alternative
Benefits [c] (3%)	$100 and $500	$120 and $520	$250 and $720.
Costs [d]	−$210	−$170	−$180.
Net Benefits	$310 and $710	$290 and $690	$430 and $900.
Benefits [c] (7%)	$90 and $450	$100 and $470	$230 and $650.
Costs [d]	−$210	−$170	−$180
Net Benefits	$300 and $660	$280 and $640	$400 and $820.

[a] We focus results to provide a snapshot of costs and benefits in 2023, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.

[c] Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 3 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate benefits from reductions in CO_2 emissions. The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. *See Louisiana* v. *Biden,* No. 21–cv–01074–JDC–KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposal conducted pursuant to E.O. 12866. Please see Chapter 5, Section 5.2 of the RIA for more discussion. In addition, there are important unquantified water quality benefits and benefits associated with reductions in other air pollutants.

[d] The costs presented in this table are 2023 annual estimates for each alternative analyzed. An NPV of costs was calculated using a 3.76% real discount rate consistent with the rate used in IPM's objective function for cost-minimization.

TABLE IX–7—MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE PROPOSED AND LESS AND MORE STRINGENT ALTERNATIVES FOR 2026 FOR THE U.S.

[Millions of 2016$] [a] [b]

	Proposed rule	Less stringent alternative	More stringent alternative
Benefits [c] (3%)	$9,300 and $18,000	$4,300 and $10,000	$9,100 and $19,000.
Costs [d]	$1,100	−$49	$1,600.
Net Benefits	$8,200 and $17,000	$4,300 and $10,000	$7,500 and $17,000.
Benefits [c] (7%)	$8,400 and $16,000	$3,800 and $9,300	$8,200 and $17,000.
Costs [d]	$1,100	−$49	$1,600
Net Benefits	$7,300 and $15,000	$9,300 and $3,900	$6,600 and $15,000.

[a] We focus results to provide a snapshot of costs and benefits in 2026, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.

[b] Rows may not appear to add correctly due to rounding.

[c] Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 3 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate benefits from reductions in CO_2 emissions. The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. See *Louisiana* v. *Biden,* No. 21–cv–01074–JDC–KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposal conducted pursuant to E.O. 12866. Please see Chapter 5, Section 5.2 of the RIA for more discussion. In addition, there are important unquantified water quality benefits and benefits associated with reductions in other air pollutants.

[d] The costs presented in this table are 2026 annual estimates for each alternative analyzed. An NPV of costs was calculated using a 3.76% real discount rate consistent with the rate used in IPM's objective function for cost-minimization.

TABLE IX–8—MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE PROPOSED AND LESS AND MORE STRINGENT ALTERNATIVES FOR 2030 FOR THE U.S.

(Millions of 2016$) [a] [b]

	Proposed rule	Less stringent alternative	More stringent alternative
Benefits [c] (3%)	$9,400 and $20,000	$4,300 and $11,000	$9,200 and $21,000.
Costs [d]	$1,600	$1,600	$2,200.
Net Benefits	$7,700 and $18,000	$2,800 and $9,700	$7,000 and $19,000.
Benefits [c] (7%)	$8,400 and $18,000	$3,900 and $10,000	$8,300 and $19,000.
Costs [d]	$1,600	$1,600	$2,200.
Net Benefits	$6,800 and $16,000	$2,300 and $8,400	$6,100 and $16,000.

[a] We focus results to provide a snapshot of costs and benefits in 2030, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.

[b] Rows may not appear to add correctly due to rounding.

[c] Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 3 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate benefits from reductions in CO_2 emissions. The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. See *Louisiana* v. *Biden,* No. 21–cv–01074–JDC–KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposed rule conducted pursuant to E.O. 12866. Please see Chapter 5, Section 5.2 of the RIA for more discussion. In addition, there are important unquantified water quality benefits and benefits associated with reductions in other air pollutants.

[d] The costs presented in this table are 2030 annual estimates for each alternative analyzed. An NPV of costs was calculated using a 3.76% real discount rate consistent with the rate used in IPM's objective function for cost-minimization.

In addition, Table IX–9 presents estimates of the present value (PV) of the monetized benefits and costs and the equivalent annualized value (EAV), an estimate of the annualized value of the net benefits consistent with the present value, over the twenty-year period of 2023 to 2042. The estimates of the PV and EAV are calculated using discount rates of 3 and 7 percent as directed by OMB's Circular A–4 and are presented in 2016 dollars discounted to 2022.

TABLE IX–9—MONETIZED ESTIMATED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE PROPOSED RULE AND LESS AND MORE STRINGENT ALTERNATIVES, 2023 THROUGH 2042

(Millions 2016$, discounted to 2022) [a]

	3 Percent discount rate		7 Percent discount rate	
	PV	EAV	PV	EAV
Benefits				
Proposed Rule	$250,000	$17,000	$150,000	$14,000
Less Stringent Alternative	150,000	9,500	88,000	7,800
More Stringent Alternative	270,000	17,000	160,000	14,000
Compliance Costs				
Proposed Rule	22,000	1,500	14,000	1,300
Less Stringent Alternative	20,000	1,300	12,000	1,100
More Stringent Alternative	28,000	1,900	18,000	1,700
Net Benefits				
Proposed Rule	220,000	15,000	130,000	12,000
Less Stringent Alternative	120,000	8,100	70,000	6,600
More Stringent Alternative	230,000	15,000	130,000	12,000

[a] The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. See *Louisiana* v. *Biden,* No. 21–cv–01074–JDC–KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposed rule conducted pursuant to E.O. 12866.

As shown in Table IX–9, the PV of the benefits of this proposed rule, discounted at a 3-percent discount rate, is estimated to be about $250,000 million, with an EAV of about $17,000 million. At a 7-percent discount rate, the PV of the benefits is estimated to be $150,000 million, with an EAV of about $14,000 million. The PV of the compliance costs, discounted at a 3-percent rate, is estimated to be about $22,000 million, with an EAV of about $1,500 million. At a 7-percent discount rate, the PV of the compliance costs is estimated to be about $14,000 million, with an EAV of about $1,300 million.

In addition to the analysis of costs and benefits, EPA also estimated the impacts on projected 2023 and 2026 ozone design values that are expected from the EGU and non-EGU control alternatives in this proposed rule. As described above, the alternative scenarios include the proposed rule along with scenarios that reflect less stringent and more stringent alternatives for EGUs and non-EGUs. The projected ozone design values and ozone impacts estimated in 2023 and 2026 for the proposed, less stringent, and more stringent alternatives are provided in Appendix 3B of the RIA. In summary, the differences in the amount of ozone reduction across the three alternatives at individual receptors in 2023 are consistent with the relative changes in NO_X emissions in this year under the different scenarios. Overall, in 2023 the estimated ozone reductions from all three of the alternatives are projected to be less than 0.1 ppb at most receptors. The exceptions are at certain receptors in Connecticut, Illinois, Texas, and Utah where impacts are between 0.1 and 0.2 ppb. In 2026, the largest impacts in the proposed rule are estimated at the two receptors in Texas (*i.e.,* Brazoria County and Harris County), where the average reduction is 1.3 ppb. Elsewhere in 2026, the average reductions for the proposed rule are on the order of 0.5 ppb at receptors in Connecticut, Illinois, and Wisconsin. The average reduction for the four receptors in Utah is approximately 0.3 ppb, while the average reduction at receptors in Colorado and California are approximately 0.2 ppb. Overall, the less stringent alternative provides approximately 0.1 to 0.3 ppb less ppb reduction (*i.e.,* 30 to 40 percent less reduction), on average, compared to the proposed rule at receptors in the East and in Colorado and Utah. The more stringent alternative does not appear to provide any notable additional ozone reductions compared to the proposed rule in all receptor areas, except at receptors in Connecticut and Texas where the average reduction increases by 0.1 ppb and 0.2 ppb with the more stringent alternative, respectively.

Examining the projected average and maximum design values in 2023 at individual receptors for the proposed, less stringent, and more stringent alternatives indicates that three of the receptors included in this impact analysis are projected to change attainment status in 2023 as a result of this proposed rule. Specifically, receptors in Clark County, Nevada, Butte County, California, and Riverside County Californian (Monitor ID: 060650008) are projected to switch from maintenance-only in the 2023 baseline to attainment and the receptor in Harris County, Texas is projected to switch from nonattainment to maintenance-only under any of the alternatives in 2023. In 2026, six of the receptors in this analysis are projected to change attainment status as a result of the emissions reductions in this proposed rule. Specifically, Calaveras County, California, Brazoria County, Texas, and in Kenosha County, Wisconsin (Monitor ID: 550590025) are projected to switch from maintenance-only to attainment in 2026 and a receptor in Riverside County, California (Monitor ID: 060650016) is projected to switch from nonattainment to maintenance under any of the alternatives. The receptor in Douglas County, Colorado and one of the receptors in Cook County, Illinois (Monitor ID: 170310076) are projected to switch from maintenance-only to attainment under the proposed and more stringent alternatives, but these receptors are projected to remain as maintenance-only in the less stringent alternative. The projected design values and additional information on the ozone impact analysis can be found in Appendix 3B of the proposed rule RIA.

X. Summary of Proposed Changes to the Regulatory Text for the Federal Implementation Plans and Trading Programs for EGUs

This section describes the proposed amendments to the regulatory text that would implement the proposed findings and remedy discussed elsewhere in this proposed rule with respect to EGUs. The primary CFR amendments would be revisions to the FIP provisions addressing states' good neighbor obligations related to ozone in 40 CFR part 52 as well as the revisions to the regulations for the CSAPR NO_X Ozone Season Group 3 Trading Program in 40 CFR part 97, subpart GGGGG. In conjunction with the amendments to the Group 3 trading program, the monitoring, recordkeeping, and reporting regulations in 40 CFR part 75 would be amended to reflect the addition of certain new reporting requirements associated with the amended trading program and the administrative appeal provisions in 40 CFR part 78 would be amended to identify certain additional types of appealable decisions of the EPA Administrator under the amended trading program. The proposed provisions to address the transition of the EGUs in certain states from the Group 2 trading program to the Group 3 trading program would be implemented in part through revisions to regulations noted above and in part through revisions to the regulations for the Group 2 trading program in 40 CFR part 97, subpart EEEEE.

In addition to these primary amendments, certain revisions are proposed to the regulations for the other CSAPR trading programs in 40 CFR part 97, subparts AAAAA through EEEEE, and the Texas SO_2 Trading Program in 40 CFR part 97, subpart FFFFF, for conformity with the proposed amended provisions of the Group 3 trading program, as discussed in Section VII.B.12 of this proposed rule. Documents have been included in the docket for this proposed rule showing all of the proposed revisions in redline-strikeout format.

A. Amendments to FIP Provisions in 40 CFR Part 52

The CSAPR, CSAPR Update, and Revised CSAPR Update FIP requirements related to ozone season NO_X emissions are set forth in 40 CFR 52.38(b) as well as other sections of part 52 specific to each covered state. The existing text of § 52.38(b)(1) identifies the trading program regulations in 40 CFR part 97, subparts BBBBB, EEEEE, and GGGGG as constituting the relevant FIP provisions relating to seasonal NO_X emissions and transported ozone pollution. Because the EPA is proposing in this rulemaking to establish new or amended FIP requirements not only for the types of EGUs covered by the trading programs but also for other types of sources, a proposed amendment to § 52.38(b)(1) would clarify that the trading programs constitute the FIP provisions only for the sources meeting the applicability requirements of the trading programs. A parallel clarification would be added to §§ 52.38(a)(1) and 52.39(a) with respect to the CSAPR FIP requirements relating to annual NO_X emissions, SO_2 emissions, and transported fine particulate pollution.

The states whose EGU sources are required to participate in the CSAPR NO_X Ozone Season Group 1, Group 2, and Group 3 trading programs under the FIPs established in CSAPR, the CSAPR Update, and the Revised CSAPR Update, as well as the control periods for which those requirements apply, are identified in § 52.38(b)(2). Proposed amendments to this paragraph would expand the applicability of the Group 3 trading program to sources in the thirteen additional states that the EPA is proposing to add to the Group 3 trading program starting with the 2023 control period and would end the applicability of the Group 2 trading program (with the exception of certain provisions) for sources in eight of the thirteen states after the 2022 control period, as discussed in Section VII.B.2 of this proposed rule.[339] The current subparagraphs within § 52.38(b)(2) would also be renumbered to clarify the organization of the provisions and to facilitate cross-references from other regulatory provisions. Regarding the two states currently participating in the Group 2 trading program through approved SIP revisions that replaced the previous FIPs issued under the CSAPR Update (Alabama and Missouri), a provision indicating that EPA would no longer administer the state trading programs adopted under those SIP revisions after the 2022 control period would be added at § 52.38(b)(16)(ii)(B).

In the Revised CSAPR Update, the EPA established several options for states to revise their SIPs to modify or replace the FIPs applicable to their sources while continuing to use the Group 3 trading program as the mechanism for meeting the states' good neighbor obligations. Existing § 52.38(b)(10), (11), and (12) establish options to replace allowance allocations for the 2022 control period, to adopt an abbreviated SIP revision for control periods in 2023 or later years, and to adopt a full SIP revision for control periods in 2023 or later years, respectively. As discussed in Section VII.D of this proposed rule, the EPA is proposing to retain these SIP revision options and to make them available for all states that would be covered by the Group 3 trading program after the proposed geographic expansion. The option under § 52.38(b)(10) to replace allowance allocations for a single control period would be amended to be available for the 2024 control period, with attendant revisions to the years and dates shown in § 52.38(b)(10) (multiple paragraphs) and (b)(17)(i) as well as the Group 3 trading program regulations, as discussed in Section X.B of this proposed rule. The options under § 52.38(b)(11) and (12) to adopt abbreviated or full SIP revisions would be amended to be available starting with the 2025 control period, with attendant revisions to § 52.38(b)(11)(iii), (b)(12)(iii), and (b)(17)(ii).[340]

The proposed changes with respect to set-asides, the treatment of units in Indian country, and recordation schedules discussed in Section VII.B.9 of this proposed rule, although implemented largely through proposed amendments to the Group 3 trading program regulations, would also be implemented in part through proposed amendments to § 52.38(b)(11) and (12). First, the text in § 52.38(b)(11)(iii)(A) and (b)(12)(iii)(A) identifying the portion of each state trading budget for which a state could establish state-determined allowance allocations would be revised to exclude any allowances in a new unit set-aside, Indian country new unit set-aside, or Indian country existing unit set-aside. Second, the text in § 52.38(b)(12)(vi) identifying provisions that states could not adopt into their SIPs (because the provisions concern regulation of sources in Indian country not subject to a state's CAA implementation planning authority) would be revised to include the provisions of the amended Group 3 trading program addressing allocation and recordation of allowances from all types of set-asides. Third, the text in § 52.38(b)(12)(vii) authorizing the EPA to modify the previous approval of a SIP revision with regard to the assurance provisions ''if and when a covered unit is located in Indian country'' would be revised to account for the fact that at least one covered unit would already be located in Indian country not subject to a state's jurisdiction if the geographic expansion proposed in this rulemaking

[339] Both the current text of § 52.38(b)(2) and the proposed amended text expressly encompass sources in Indian country within the respective states' borders.

[340] No state currently in the Group 3 trading program has submitted a SIP revision to make use of these options in control periods before the control periods in which the options could be used under the proposed amendments.

is finalized. Finally, the text in § 52.38(b)(11)(iii)(B) and (b)(12)(iii)(B) would be revised to amend the deadline for states to submit state-determined allowance allocations to the EPA from June 1 in the third year before the relevant control period to June 1 in the year before the relevant control period.

The proposed transitional provisions discussed in Section VII.B.11 of this proposed rule to convert certain 2017–2022 Group 2 allowances to Group 3 allowances and to recall certain 2023–2024 Group 2 allowances, although promulgated as amendments to the Group 2 trading program regulations, would necessarily be implemented after the end of the 2022 control period. Proposed amendments clarifying that these provisions continue to apply to the relevant sources and holders of allowances notwithstanding the transition of certain states out of the Group 2 trading program after the 2022 control period would be added at § 52.38(b)(14)(iii)(F) and (G). Cross-references clarifying that EPA's allocations of the converted Group 3 allowances would not be subject to modification through SIP revisions would also be added to the existing provisions at § 52.38(b)(11)(iii)(D) and (b)(12)(iii)(D).

The general FIP provisions applicable to all states covered by this proposed rule as set forth in § 52.38(b)(2) would be replicated in the state-specific subparts of 40 CFR part 52 for each of the thirteen states that the EPA is proposing to add to the Group 3 trading program.[341] In each such state-specific CFR subpart, provisions would be added indicating that sources in the state are required to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program with respect to emissions starting in 2023. Provisions would also be added repeating the substance of § 52.38(b)(13)(i), which generally provides that the Administrator's full and unconditional approval of a full SIP revision correcting the same SIP deficiency that is the basis for a FIP promulgated in this rulemaking would cause the FIP to no longer apply to sources subject to the state's CAA implementation planning authority, and § 52.38(b)(14)(ii), which generally provides the EPA with authority to complete recordation of EPA-determined allowance allocations for any control period for which EPA has already started such recordation notwithstanding the approval of a state's SIP revision establishing state-determined allowance allocations.

For each of the eight states that the EPA is proposing to remove from the Group 2 trading program, the current provisions of the state-specific CFR subparts indicating that sources in the state are required to participate in that trading program would be revised to end that requirement with respect to emissions after 2022, and a further provision would be added repeating the substance of § 52.38(b)(14)(iii), which identifies certain provisions that continue to apply to sources and allowances notwithstanding discontinuation of a trading program with respect to a particular state.[342] In addition, for the six states that during their time in the Group 2 trading program have not exercised the option to adopt full SIP revisions to replace the FIPs issued under the CSAPR Update (all but Alabama and Missouri), obsolete provisions concerning the unexercised SIP revision option would be removed.

No amendments with respect to FIP requirements for EGUs would be made to the state-specific CFR subparts for the twelve states whose sources currently participate in the Group 3 trading program[343] except as needed to update cross-references or to implement the proposed changes related to the treatment of Indian country, as discussed in Section X.D of this proposed rule.

B. Amendments to Group 3 Trading Program and Related Regulations

To implement the geographic expansion of the Group 3 trading program and the revised trading budgets that would be established under the new and amended FIPs proposed in this rulemaking, several sections of the Group 3 trading program regulations would be amended. Revisions identifying the applicable control periods, deadlines for certification of monitoring systems, and deadlines for commencement of quarterly reporting for sources not previously covered by the Group 3 trading program would be made at §§ 97.1006(c)(3)(i), 97.1030(b)(1), and 97.1034(d)(2)(i), respectively. Revisions identifying the proposed new or revised budgets and new unit set-asides for the 2023 and 2024 control periods for all covered states would be made at § 97.1010(a)(1) and (b)(1), respectively.

Each of the proposed enhancements to the Group 3 trading program discussed in Section VII.B of this proposed rule would also be implemented primarily through revisions to the trading program regulations. The dynamic budget-setting process discussed in Section VII.B.4 of this proposed rule would be implemented at § 97.1010(a)(2) and (3), and the associated revised process for determining variability limits and assurance levels discussed in Section VII.B.5 of this proposed rule would be implemented at § 97.1010(e). The Group 3 allowance bank recalibration process discussed in Section VII.B.6 of this proposed rule would be implemented at § 97.1026(d). The backstop daily NO_X emissions rate component of the primary emissions limitation discussed in Section VII.B.7 would be implemented at §§ 97.1006(c)(1)(i) and 97.1024(b)(1) and (3), accompanied by the addition of a definition of ''backstop daily NO_X emissions rate'' and modification of the definition of ''CSAPR NO_X Ozone Season Group 3 allowance'' in § 97.1002. The secondary emissions limitation for sources found responsible for exceedances of the assurance levels discussed in Section VII.B.8 of this proposed rule would be implemented at §§ 97.1006(c)(1)(iii) and (iv) and (c)(3)(ii) and 97.1025(c), accompanied by the addition of a definition of ''CSAPR NO_X Ozone Season Group 3 secondary emissions limitation'' in § 97.1002.

The proposed changes relating to set-asides, the treatment of Indian country, unit-level allowance allocations, and recordation schedules discussed in Section VII.B.9 of this proposed rule would be implemented through revisions to multiple sections of §§ 97.1010, 97.1011, 97.1012, and 97.1021, as well as limited revisions to 97.1002 (definition of ''allocate or allocation'') and 97.1006(b)(2). In § 97.1010, paragraphs (b), (c), and (d) would address the amounts for each control period of the new unit set-asides, Indian country new unit set-asides, and Indian country existing unit set-asides, respectively. Paragraphs (c) and (d) would reflect the discontinuation of Indian country new unit set-asides after the 2022 control period and the establishment of Indian

[341] *See* proposed §§ 52.54(b) (Alabama), 52.184(a) (Arkansas), 52.440(d) (Delaware), 52.1240(d) (Minnesota), 52.1824(a) (Mississippi), 52.1326(b) (Missouri), 52.1492 (Nevada), 52.1930(a) (Oklahoma), 52.2240(e) (Tennessee), 52.2283(d) (Texas), 52.2356 (Utah), 52.2587(e) (Wisconsin), and 52.2638(a) (Wyoming).

[342] *See* proposed §§ 52.54(b) (Alabama), 52.184(a) (Arkansas), 52.1824(a) (Mississippi), 52.1326(b) (Missouri), 52.1930(a) (Oklahoma), 52.2240(e) (Tennessee), 52.2283(d) (Texas), and 52.2587(e) (Wisconsin).

[343] *See* proposed §§ 52.731(b) (Illinois), 52.789(b) (Indiana), 52.940(b) (Kentucky), 52.984(d) (Louisiana), 52.1084(b) (Maryland), 52.1186(e) (Michigan), 52.1584(e) (New Jersey), 52.1684(b) (New York), 52.1882(b) (Ohio), 52.2040(b) (Pennsylvania), 52.2440(b) (Virginia), and 52.2540(b) (West Virginia).

country existing unit set-asides starting with the 2023 control period.[344]

The proposed revisions to § 97.1011 would refocus the section exclusively on allocation to ''existing'' units from the portion of each state emissions budget not reserved in a new unit set-aside or Indian country new unit set-aside. In § 97.1011(a), the provision currently in § 97.1011(a)(1) requiring allocations to existing units to be made in the amounts provided in notices of data availability (NODAs) issued by the EPA would be split into two separate provisions, with paragraph (a)(1) applying to existing units in the state and areas of Indian country covered by the state's CAA implementation planning authority and paragraph (a)(2) applying to existing units in areas of Indian country not covered by the state's CAA implementation planning authority.[345] This split would facilitate the submission and approval of SIP revisions by states interested in submitting state-determined allowance allocations for the units over which they exercise CAA implementation authority, while leaving allocations to any units outside their authority to be addressed either by the EPA or by the relevant tribe under an approved tribal implementation plan. The proposed dynamic process for determining default allocations to existing units of allowances from state trading budgets starting with the 2025 control period would be set forth in revised § 97.1011(b), while the current provisions of § 97.1011(b), which concern timing and notice procedures for allocations to new units, would be relocated to § 97.1012. The provisions addressing incorrectly allocated allowances at § 97.1011(c) would be streamlined by relocating the portions applicable to new units to § 97.1012(c). In addition, as discussed in Section VII.B.9.d of this proposed rule, § 97.1011(c)(5) would be revised to provide that, starting with the 2024 control period, any incorrectly allocated allowances recovered after May 1 of the year following the control period would not be reallocated to other units in the state but instead would be transferred to a surrender account.

The proposed revisions to § 97.1012 would retain the section's current focus on allocations to ''new'' units, generally combining the current provisions at § 97.1012 with the current provisions at § 97.1011(b) and (c) that address new units. The text of multiple paragraphs in both § 97.1012(a) and (b) would be revised as needed to reflect the change in treatment of Indian country discussed in Section VII.B.9.a of this proposed rule, under which the new unit set-asides would be used to provide allowance allocations to new units both in non-Indian country and Indian country within the borders of the respective states for control periods starting in 2023.[346] The timing and notice provisions in proposed § 97.1012(a)(13) and (b)(13) are relocated from current § 97.1011(b)(1) and (2). The text of § 97.1012(c), addressing incorrect allocations to new units, is largely relocated from § 97.1011(c) (which addresses incorrect allocations to existing units) and reflects a parallel proposed revision addressing the disposition of recovered allowances, as discussed in Section VII.B.9.d of this proposed rule.

The proposed amendments to § 97.1021 would implement three distinct sets of changes discussed in Sections VII.B.9 and VII.D.1 of this proposed rule. First, revisions to § 97.1021(b) through (e) would replace the previous schedule for recording Group 3 allowances for the 2023 and 2024 control periods established in the Revised CSAPR Update with an updated recordation schedule tailored to the expected timing for issuance of a final rule in this rulemaking. The updated schedule would also reflect elimination of the unused former option for states to provide state-determined allowance allocations for the 2022 control period and the proposed establishment of a substantively equivalent new option for states to provide state-determined allowance allocations for the 2024 control period. Second, revisions to § 97.1021(f) would change the schedule for recording allocations to existing units for future control periods from July 1 of the year three years before the control period to July 1 of the year before the control period. Finally, revisions to § 97.1021(g) through (j) would end recordation for Indian country new unit set-asides after allocations for the 2022 control period, begin recordation for Indian country existing unit set-asides starting with allocations for the 2023 control period, and modify the text to eliminate references to state-determined allocations of allowances from new unit set-asides.

Implementation of the proposed revisions to the Group 3 trading program would also be accomplished in part through amendments to regulations in other CFR parts. In 40 CFR part 75, which contains detailed monitoring, recordkeeping, and reporting requirements applicable to sources covered by the Group 3 trading program, the additional recordkeeping and reporting requirements discussed in Section VII.B.10.b of this proposed rule would be implemented through the addition of §§ 75.72(f) and 75.73(f)(1)(ix) and (x) and revisions to § 75.75, and the procedures for calculating daily total heat input and daily total NO_X emissions and for apportioning NO_X mass emissions monitored at a common stack among the individual units using the common stack would be added at sections 5.3.3, 8.4(c), and 8.5.3 of appendix F to part 75. In 40 CFR part 78, which contains the administrative appeal procedures applicable to decisions of the EPA Administrator under the Group 3 trading program, § 78.1(b)(19) would be amended to list additional decisions made as part of the trading program enhancements that would be appealable under those procedures.

C. Transitional Provisions

As discussed in Section VII.D.11 of this proposed rule, the EPA is proposing several transitional provisions for sources entering the Group 3 trading program. The provisions discussed in Section VII.D.11.a of this proposed rule, concerning the prorating of state emissions budgets, assurance levels, and unit-level allocations for the 2023 control period, would be implemented through the Group 3 trading program regulations. Specifically, the state emissions budgets for the 2023 control period would be prorated according to procedures set out at § 97.1010(a)(1)(ii). Variability limits for the 2023 control period, and the resulting assurance levels, would be computed under § 97.1010(e) from the prorated state emissions budgets. Unit-level

[344] The current § 97.1011(c), which addresses the relationships of set-asides and variability limits to state trading budgets, would be relocated to § 97.1011(f).

[345] An additional provision currently in § 97.1011(a)(1), which clarifies that an allocation or lack of allocation to a unit in a NODA does not constitute a determination by the EPA that the unit is or is not a CSAPR NO_X Ozone Season Group 3 unit, would be relocated to § 97.1011(a)(3). The current § 97.1011(a)(2), which provides for certain existing units that cease operations to receive allocations for their first five control periods of non-operation and provides for the allowances for subsequent control periods to be allocated to the relevant state's new unit set-asides, is inconsistent with the proposed revisions to the set-asides and the default allowance allocation process, as discussed in Section VII.B.9 of this proposed rule, and would be removed as obsolete.

[346] Revisions are also proposed to the text of § 97.1012(a) and (b) for the control periods in 2021 and 2022 consistent with the proposed revisions to the parallel provisions in the regulations for the other CSAPR trading programs, generally calling for allocations to units in areas of Indian country subject to a state's CAA implementation planning authority to be made from the new unit set-asides instead of from the Indian country new unit set-asides.

allocations to existing units for the 2023 control period would be computed from the prorated state emissions budgets according to procedures substantively the same as the procedures codified in § 97.1011(b) for calculating default allocations to existing units for later control periods, as discussed in Section VII.B.9.b of this proposed rule, and would be announced in the notice of data availability issued under § 97.1011(a)(1) and (2) for the 2023 and 2024 control periods.

The remaining transitional provisions would be implemented through the Group 2 trading program regulations. The creation of an additional Group 3 allowance bank for the 2023 control period through the conversion of banked 2017–2022 Group 2 allowances as discussed in Section VII.B.11.b of this document would be implemented at § 97.826(e).[347] Related provisions addressing the use of Group 3 allowances to satisfy after-arising compliance obligations under the Group 2 trading program or the Group 1 trading program would be implemented at §§ 97.826(f)(2) and 97.526(e)(3), respectively, and related provisions addressing recordation of late-arising allocations of Group 1 allowances would be implemented at § 97.526(d)(2)(iii). The recall of Group 2 allowances previously issued for the 2023 and 2024 control periods as discussed in Section VII.B.11.c of this document would be implemented at § 97.811(e).

Decisions of the Administrator related to the allowance bank creation provisions and the allowance recall provisions would be identified as appealable decisions under 40 CFR part 78 through revisions to § 78.1(b)(17)(viii) and (ix).

D. Clarifications and Conforming Revisions

As discussed in Section VII.B.12 of this proposed rule, the EPA is proposing to make revisions to the provisions regarding allowance allocations for units in Indian country in all the CSAPR trading programs so that instead of distinguishing among units based on whether they are or are not located in Indian country, the revised provisions would distinguish among units based on whether they are or are not covered by a state's CAA implementation planning authority. The proposed revisions would be implemented in multiple paragraphs of §§ 97.411(b), 97.412, 97.511(b), 97.512, 97.611(b), 97.612, 97.711(b), 97.712, 97.811(b), and 97.812. The associated revisions to states' options regarding SIP revisions to establish state-determined allowance allocations for units covered by their CAA implementation planning authority would be implemented in multiple paragraphs of §§ 52.38(a) and (b) and 52.39 as well as the state-specific subparts of 40 CFR part 52.

As also discussed in Section VII.B.12 of this proposed rule, the EPA is proposing to revise the recordation schedule for allowance allocations to existing units under all the CSAPR trading programs, as well as the Texas SO_2 Trading Program, so that starting with the 2025 control period the allocation deadline would generally be July 1 of the year before the control period instead of July 1 of the year 3 years before the control period. The revisions would be implemented at §§ 97.421(f)(2), 97.521(f)(2), 97.621(f)(2), 97.721(f)(2), 97.821(f), and 97.921(b)(2).

Certain other revisions to the regulatory text in the FIP and trading program regulations are proposed as non-substantive clarifications. First, in the Group 2 trading program regulations, the paragraphs in § 97.810 setting forth the amounts of state emissions budgets, new unit set-asides, Indian country new unit set-asides, and variability limits for states that the EPA is proposing to transition out of the Group 2 trading program would be modified to indicate that the amounts are applicable under that program only for control periods through 2022.

Second, as noted in Section VII.F.1 of this proposed rule, the existing option for states subject to the NO_X SIP Call to expand applicability of the Group 2 trading program to include certain large non-EGU boilers and combustion turbines would become obsolete if this rule is finalized as proposed because no NO_X SIP Call states would continue to be covered by the Group 2 trading program. The proposed elimination of the obsolete option would be implemented in part through revisions to § 52.38(b)(8) (multiple paragraphs), (b)(9) (multiple paragraphs), (b)(13)(ii), (b)(14)(i)(F), and (b)(16)(i)(B), and in part through revisions to the Group 2 trading program regulations at §§ 97.806(c)(2) and (3), 97.825, and 97.802 (removal of the definitions of ''base CSAPR NO_X Ozone Season Group 2 source'' and ''base CSAPR NO_X Ozone Season Group 2 unit'' and modification of the definitions of ''assurance account'', ''common designated representative'', common designated representative's assurance level'', and ''common designated representative's share'').

Third, to clarify the regulatory text, the EPA is proposing to remove the language in the Group 3 trading program regulations finalized in the Revised CSAPR Update relating to the ''supplemental allowances'' issued for the 2021 control period in current §§ 97.1002 (definition of ''common designated representative's assurance level''), 97.1006(c)(2)(iii), 97.1010(d), and 97.1011(a)(1). In place of the removed language, the EPA proposes to restate the amounts of the state emissions budgets for the 2021 control period in § 97.1010(a)(1)(i) so as to include the amounts of the supplemental allowances in the restated budget amounts. The revised language would be substantively equivalent to and simpler than the current language.

Fourth, in 40 CFR part 75, the EPA proposes to remove obsolete text in § 75.73(c) and (f) to clarify the context for other text that would be added to the section, as discussed in Section X.B.

Finally, the EPA proposes to update cross-references throughout 40 CFR parts 52 and 97 for consistency with the other amendments proposed in this rulemaking.

XI. Statutory and Executive Orders Reviews

Additional information about these statutes and Executive Orders (''E.O.'') can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders*.

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This proposed rule is an economically significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. This proposed rule is in response to a court-ordered legal mandate and proposes to implement EGU and novel non-EGU NO_X ozone season emissions reductions as part of the overall strategy for addressing interstate transport of ozone pollution for the 2015 ozone NAAQS. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this proposed rule. This analysis, which is contained in the ''Regulatory Impact Analysis for the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard'' [EPA–452/R–15–009], is available in the docket and is briefly summarized in Section IX of this proposed rule.

[347] The current provisions at § 97.826(e) would be relocated to § 97.826(f)(1) and (3).

B. Paperwork Reduction Act (PRA)

1. Information Collection Request for Electric Generating Units

The information collection activities in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2709.01. EPA has placed a copy of the ICR in the docket for this rule, and it is briefly summarized here.

EPA is proposing an information collection request (ICR), related specifically to electric generating units (EGU), for the proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard. The proposed rule would amend the Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 3 trading program addressing seasonal NO_X emissions in various states. Under the proposed amendments, all EGU sources in the original twelve Group 3 states (Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia) would remain. Additionally, EGU sources in eight states (Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin) currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program would transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 ozone season. Further, sources in five states not currently covered by any CSAPR NO_X ozone season trading program would join the revised Group 3 trading program: Delaware, Minnesota, Nevada, Utah, and Wyoming. In total, EGU sources in 25 states would now be covered by the Group 3 program.

There is an existing ICR (OMB Control Number 2060–0667), that includes information collection requirements placed on EGU sources for the six Cross-State Air Pollution Rule (CSAPR) trading programs addressing sulfur dioxide (SO_2) emissions, annual nitrogen oxides (NO_X) emissions, or seasonal NO_X emissions in various sets of states, and the Texas SO_2 trading program which is modeled after CSAPR. This ICR accounts for the additional respondent burden related to the amendments to the CSAPR NO_X Ozone Group 3 trading program.

The principal information collection requirements under the CSAPR and Texas trading programs relate to the monitoring and reporting of emissions and associated data in accordance with 40 CFR part 75. Other information collection requirements under the programs concern the submittal of information necessary to allocate and transfer emission allowances and the submittal of certificates of representation and other typically one-time registration forms.

Affected sources under the CSAPR and Texas trading programs are generally stationary, fossil fuel-fired boilers and combustion turbines serving generators larger than 25 megawatts (MW) producing electricity for sale. Most of these affected sources are also subject to the Acid Rain Program (ARP). The information collection requirements under the CSAPR and Texas trading programs and the ARP substantially overlap and are fully integrated. The burden and costs of overlapping requirements are accounted for in the ARP ICR (OMB Control Number 2060–0258). Thus, this ICR accounts for information collection burden and costs under the CSAPR NO_X Ozone Season Group 3 trading program that are incremental to the burden and costs already accounted for in both the ARP and CSAPR ICRs.

For most sources already reporting data under the CSAPR NO_X Ozone Season Group 3 or CSAPR NO_X Ozone Group 2 trading programs, there would be no incremental burden or cost, as reporting requirements will remain identical. Certain sources with a common stack configuration and/or those that are large, coal-fired EGUs, will be subject to additional emission reporting requirements under the proposed rule. These sources will need to make a one-time monitoring plan and Data Acquisition and Handling System (DAHS) update to meet the additional reporting requirements. Remaining for assessment of incremental cost and burden are only those sources in the five states not currently reporting data under a CSAPR NO_X Ozone Season program. Sources in Minnesota are already reporting data for the CSAPR NO_X Annual program with almost identical information collection requirements, requiring only a one-time monitoring plan and DAHS update. Most of the affected sources in Delaware, Nevada, Utah, and Wyoming are already reporting data as part of the Acid Rain Program, thus only requiring a monitoring plan and DAHS update as well. Four additional EGUs in Delaware already report data under SIP requirements adopted to meet the NO_X SIP Call and would face identical information requirements under this proposed rule. For the units that already report to EPA under the Acid Rain Program or the NO_X SIP Call, with the exception of any one-time costs to update monitoring plans and DAHS, all information collection costs and burden are already reflected in the previously approved ICRs for those other rules (OMB Control Nos. 2060–0258 and 2060–0445).

In total, there are an estimated 16 units in Delaware, Nevada, Utah, and Wyoming that do not already report data to EPA according to 40 CFR part 75 and that would need to implement one of the Part 75 monitoring methodologies including certification of monitoring systems or implementation of the low mass emissions methodology. These units would also require monitoring plan and DAHS updates. Of these sixteen units, two units would be expected to adopt low mass emissions (LME) as the monitoring method, thirteen would be expected to adopt Appendix D monitoring methods, and one would be expected to adopt CEMS monitoring methods.

Respondents/affected entities: Industry respondents are stationary, fossil fuel-fired boilers and combustion turbines serving electricity generators subject to the CSAPR and Texas trading programs, as well as non-source entities voluntarily participating in allowance trading activities. Potential state respondents are states that can elect to submit state-determined allowance allocations for sources located in their states.

Respondent's obligation to respond: Industry respondents: Voluntary and mandatory (Sections 110(a) and 301(a) of the Clean Air Act).

Estimated number of respondents: EPA estimates that there would be 188 industry respondents.

Frequency of response: On occasion, quarterly, and annually.

Total estimated additional burden: 1,834 hours (per year). Burden is defined at 5 CFR 1320.03(b).

Total estimated additional cost: \$396,520 (per year); includes \$210,571 annualized capital or operation & maintenance costs.

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 the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to

OMB's Office of Information and Regulatory Affairs via email to *OIRA_submission@omb.eop.gov,* Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than May 6, 2022. The EPA will respond to any ICR-related comments in the final rule.

2. Information Collection Request for Non-Electric Generating Units

The information collection activities in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2705.01. The EPA has filed a copy of the non-EGU ICR in the docket for this rule, and it is briefly summarized here.

ICR No. 2705.01 is a new request and it addresses the burden associated with new regulatory requirements under the proposed rule. Owners and operators of certain non-Electric Generating Unit (non-EGU) industry stationary sources will potentially modify or install new emission controls and associated monitoring systems to meet the nitrogen oxides (NO_X) emission limits of this proposed rule. The burden in this ICR reflects the new monitoring, calibrating, recordkeeping, reporting and testing activities required by industry and the administrative review conducted by the states of the associated industry activities. This information is being collected to assure compliance with the proposed rule. In accordance with the Clean Air Act Amendments of 1990, any monitoring information to be submitted by sources is a matter of public record. Information received and identified by owners or operators as confidential business information (CBI) and approved as CBI by EPA, in accordance with Title 40, Chapter 1, Part 2, Subpart B, shall be maintained appropriately (see 40 CFR 2; 41 FR 36902, September 1, 1976; amended by 43 FR 39999, September 8, 1978; 43 FR 42251, September 28, 1978; 44 FR 17674, March 23, 1979).

Respondents/affected entities: The respondents/affected entities are the owners/operators of certain non-EGU industry sources in the following industry sectors: Furnaces in Glass and Glass Product Manufacturing; boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; kilns in Cement and Cement Product Manufacturing; reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; and high-emitting equipment and large boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mill.

Respondent's obligation to respond: Voluntary and mandatory. (Sections 110(a) and 301(a) of the Clean Air Act). All data that is recorded or reported by respondents is required by the proposed rule, titled ''Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard: Transport Obligations for non-Electric Generating Units''.

Estimated number of respondents: 489.

Frequency of response: The specific frequency for each information collection activity within the non-EGU ICR is shown at the end of the ICR document in the Tables 1–11. In general, the frequency varies across the monitoring, recordkeeping, and reporting activities. Some recordkeeping such as work plan preparation is a one-time activity whereas engine maintenance recordkeeping is conducted quarterly. Reporting frequency is on a quarterly and semi-annual basis.

Total estimated burden: 51,654 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $11,450,000 (average per year); includes $5,467,000 annualized capital or operation & maintenance costs.

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 the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency's need for this information from the EGU ICR and non-EGU ICR, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs via email to *OIRA_submission@omb.eop.gov,* Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than May 6, 2022. The EPA will respond to any ICR-related comments in the final rule.

C. Regulatory Flexibility Act (RFA)

The EPA certifies that this proposed action will not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (RFA). The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), as amended by the Small Business Regulatory Enforcement Fairness Act (Pub. L. 104–121), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis, unless it certifies that the proposed rule, if promulgated, will not have a significant economic impact on a substantial number of small entities (5 U.S.C. 605(b)). Small entities include small businesses, small organizations, and small governmental jurisdictions.

In 2026, EPA identified 34 small entities affected by the proposed rule, and of these 6 small entities may experience costs of greater than 1 percent of revenues. Of the 6 small entities projected to have costs greater than 1 percent of revenues, two of them operate in cost-of-service regions and would generally be able to pass any increased costs along to rate-payers. In EPA's modeling, most of the cost impacts for these small entities and their associated units are driven by lower electricity generation relative to the base case baseline. Specifically, four units reduce their generation by significant amounts, driving the bulk of the costs for all small entities. Finally, EPA's decision to exclude units smaller than 25 MW capacity from the proposed FIP, and exclusion of uncontrolled units smaller than 100 MW from backstop emission rate limits has already significantly reduced the burden on small entities by reducing the number of affected small entity-owned units. Further, in 2026 for non-EGUs, there are five small entities, and one small entity is estimated to have a cost-to-sales impact of 1.3 percent of their revenues.

The EPA has determined that an insignificant number of small entities potentially affected by the proposed rule will have compliance costs greater than 1 percent of annual revenues during the compliance period. EPA has concluded that there will be no significant economic impact on a substantial number of small entities (No SISNOSE) for this proposed rule overall. Details of this analysis are presented in Chapter 6 of the RIA, which is in the public docket.

D. Unfunded Mandates Reform Act (UMRA)

This proposed action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and will not significantly or uniquely affect small governments. Note that we expect the proposed rule to potentially have an impact on only one category of government-owned entities (municipality-owned entities). This analysis does not examine potential indirect economic impacts associated with the proposed rule, such as employment effects in industries providing fuel and pollution control equipment, or the potential effects of electricity price increases on government entities. For more information on the estimated impact on government entities, refer to the RIA, which is in the public docket.

E. Executive Order 13132: Federalism

This proposed action does not have federalism implications. If finalized, this proposed action 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.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This proposed action has tribal implications. However, it would neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law.

The EPA proposes to make a finding that interstate transport of ozone precursor emissions from 26 upwind states (Alabama, Arkansas, California, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming) is significantly contributing to downwind nonattainment or interfering with maintenance of the 2015 ozone NAAQS in other states, based on projected nitrogen oxides (NO_X) emissions in the 2023 ozone season. EPA is proposing to issue FIP requirements to eliminate interstate transport of ozone precursors from these 26 states that significantly contributes to nonattainment or interferes with maintenance of the NAAQS in other states. Under CAA section 301(d)(4), EPA proposes to extend FIP requirements to apply in Indian country located within the upwind geography of the proposed rule, including Indian reservation lands and other areas of Indian country over which EPA or a tribe has demonstrated that a tribe has jurisdiction. EPA's proposed extension is described further above in Section IV.C.2., *Application of Rule in Indian Country and Necessary or Appropriate Finding.* EPA proposes that all existing and new EGU and non-EGU sources that are located in the 301(d) FIP areas within the geographic boundaries of the covered states, and which would be subject to this rule if located within areas subject to state CAA planning authority, should be included in this rule. This proposed action has tribal implication because of the proposed extension of FIP requirements into Indian country and this proposed rule may have additional tribal implications if a new affected EGU or non-EGU is built in Indian country. To EPA's knowledge, only one existing EGU or non-EGU source is located within the 301(d) FIP areas: The Bonanza Power Plant, an EGU source, located on the Uintah and Ouray Reservation, geographically located within the borders of Utah. In general, tribes have a vested interest in how this proposed rule would affect air quality.

In the Revised CSAPR Update, EPA established default procedures for allocating CSAPR NO_X Ozone Season Group 3 allowances (''Group 3 allowances'') in amounts equal to each state emissions budget for each control period among the sources in the state for use in complying with the Group 3 trading program. Under the current Group 3 trading programs, reserved allowances are made available generally (but not exclusively [348]) to ''new'' units—which for purposes of the Revised CSAPR Update means units commencing commercial operation on or after January 1, 2019—through a ''new unit set-aside'' established for qualifying units in each state and, if areas of Indian country exist within the state's borders, a separate ''Indian country new unit set-aside'' for qualifying units in such Indian country. In this rulemaking, EPA is proposing revisions to each step of the three-step allocation process to better address units in Indian country and to better coordinate the unit-level allocation process with the proposed dynamic budget-setting process.

The EPA hosted an environmental justice webinar on October 26, 2021, that was attended by state regulatory authorities, environmental groups, federally recognized tribes, and small business stakeholders. The EPA will also continue to consult with the government of the Ute Indian Tribe of the Uintah and Ouray Reservation and plans to further consult with any other tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing this proposed regulation to solicit meaningful and timely input into its development. The EPA plans to issue tribal consultation letters addressed to 574 tribes in February 2022 after the proposed rule is signed. The EPA will likely facilitate an additional tribal consultation through a webinar before finalizing this proposed rule.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it implements a previously promulgated health-based federal standard. This action's health and risk assessments are contained in Chapter 5 of this RIA. The EPA believes that the ozone-related benefits, $PM_{2.5}$-related benefits, and CO_2-related benefits from this proposed rule will further improve children's health. Additionally, the ozone exposure analysis in Chapter 7 of the RIA suggests that nationally, children (ages 0–17) will experience at least as great a reduction in ozone exposures as adults (ages 18–64) in 2023 and 2026 under all regulatory alternatives of this proposed rulemaking.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. EPA has prepared a Statement of Energy Effects for the proposed regulatory contro*l* alternative as follows. The Agency estimates a 1 percent change in retail electricity prices on average across the contiguous U.S. in 2025, a 7.8 percent reduction in coal-fired electricity generation, a 0.15 percent increase in natural gas-fired electricity generation, and a 3.8 percent increase in renewable electricity generation in 2025 as a result of this proposed rule. EPA projects that utility power sector delivered natural gas prices will change by less than 1 percent in 2025. Details of the estimated energy effects are presented in Chapter 4 of the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA)

This proposed rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples, as specified in Executive Order 12898.[349] The documentation for this decision is contained in Section VIII. *Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement* of this Proposed rule and in Chapter 7, *Environmental Justice Impacts* of the RIA, which is in the public document. The RIA was prepared under E.O. 12866 *Regulatory Planning and Review* for this proposed rule. While the ozone exposure assessment was subject to several limitations, also described in Chapter 7 of the RIA, overall, ozone concentrations under the proposal, more stringent, and less stringent alternatives are predicted to impact demographic groups very similarly in both future years and across both EGUs and non-EGUs.

Therefore, regarding ozone concentrations, EPA does not find evidence of meaningful environmental justice concerns associated with ozone concentrations after imposition of the proposed regulatory action or alternatives under consideration. We also do not find evidence that any potential environmental justice concerns related to ozone would be meaningfully exacerbated in the regulatory alternatives under consideration, compared to the baseline. Importantly, the action described in this proposed rule is expected to lower ozone in many areas, including residual ozone nonattainment areas, and thus mitigate some pre-existing health risks of ozone across all populations evaluated.

In addition, the EPA provided the public, including those communities disproportionately impacted by the burdens of pollution, opportunities for meaningful engagement with the EPA on this action. A summary of outreach activities conducted by the Agency and what was heard from communities is provided in section VIII of this proposed rule.

K. Determinations Under CAA Section 307(b)(1) and (d)

Section 307(b)(1) of the CAA governs judicial review of final actions by the EPA. This section provides, in part, that petitions for review must be filed in the United States Court of Appeals for the District of Columbia Circuit: (i) When the agency action consists of ''nationally applicable regulations promulgated, or final action taken, by the Administrator,'' or (ii) when such action is locally or regionally applicable, but ''such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination.'' For locally or regionally applicable final actions, the CAA reserves to EPA complete discretion whether to invoke the exception in (ii).

This proposed action, if finalized, would be ''nationally applicable'' within the meaning of CAA section 307(b)(1). In the alternative, to the extent a court finds this action to be locally or regionally applicable, the Administrator proposes to exercise the complete discretion afforded to him under the CAA to make and publish a finding that this action is based on a determination of ''nationwide scope or effect'' within the meaning of CAA section 307(b)(1).[350]

This proposed action, if finalized, will implement the good neighbor provision in 26 states, spanning 8 EPA regions and 10 federal judicial circuits. The proposed action applies a uniform, nationwide analytical method and interpretation of CAA section 110(a)(2)(D)(i)(I) across these states, and the proposed rule is based on a common core of legal, technical, and policy determinations (as explained in further detail in the following paragraph). For these reasons, this proposed action is nationally applicable.

Alternatively, for these same reasons, the Administrator is exercising the discretion afforded to him by the CAA and hereby finds that this proposed action is based on multiple determinations of nationwide scope or effect for purposes of CAA section 307(b)(1).[351] Specifically, the proposed rule is based on a common core of statutory and case law analysis, factual findings, and policy determinations concerning the transport of ozone-precursor pollutants from the different states subject to it, as well as the impacts of those pollutants and the impacts of options to address those pollutants in yet other states. In this proposed action, EPA is applying its 4-step analytic framework to implement the good neighbor provision across these states, using a consistent set of policy and analytical determinations. The proposed determinations include a nationally consistent definition of receptors at Step 1 and findings identifying downwind nonattainment and maintenance receptors; the application of a nationally consistent contribution threshold at Step 2 to determine which states are linked to those receptors and should be further evaluated at Step 3; the use of a nationally consistent multi-factor test at Step 3 to determine which upwind-state contributions to nonattainment and maintenance receptors are ''significant'' and must be eliminated; and the proposed implementation at Step 4 of a nationally consistent set of emissions control strategies through emissions budgets and an integrated interstate emissions trading program for EGUs, a nationally consistent set of other compliance requirements for EGUs, and a nationally consistent set of enforceable emissions limits and associated compliance requirements for certain non-EGU sources in several industrial sectors across 23 states. Finally, the technical, scientific, and engineering information in support of these proposed determinations relies on a nationally consistent set of air quality modeling analyses and other nationally consistent analytical methods, as set forth elsewhere in this proposed rule and in the relevant supporting documents in the docket for this proposed rule.

Therefore, pursuant to CAA section 307(b), any petitions for review of this action, if and when it is finalized, must be filed in the D.C. Circuit within 60 days from the date such final action is published in the **Federal Register**.

This action is subject to the provisions of section 307(d). CAA section 307(d)(1)(B) provides that section 307(d) applies to, among other things, ''the promulgation or revision of an implementation plan by the Administrator under [CAA section 110(c)].'' 42 U.S.C. 7407(d)(1)(B). This action, among other things, proposes new federal implementation plans pursuant to the authority of section 110(c). To the extent any portion of this rulemaking, if finalized, is not expressly identified under section 307(d)(1)(B),

[349] 59 FR 7629, February 16, 1994.

[350] In proposing to invoke the exception by making and publishing a finding that this final action is based on a determination of nationwide scope or effect, the Administrator is taking into account a number of policy considerations, including his judgment balancing the benefit of obtaining the D.C. Circuit's authoritative centralized review versus allowing development of the issue in other contexts and the best use of agency resources.

[351] In the report on the 1977 Amendments that revised section 307(b)(1) of the CAA, Congress noted that the Administrator's determination that the ''nationwide scope or effect'' exception applies would be appropriate for any action that has a scope or effect beyond a single judicial circuit. *See* H.R. Rep. No. 95–294 at 323, 324, reprinted in 1977 U.S.C.C.A.N. 1402–03.

the Administrator determines that the provisions of section 307(d) apply to such final action. *See* CAA section 307(d)(1)(V) (the provisions of section 307(d) apply to ''such other actions as the Administrator may determine'').

List of Subjects

40 CFR Part 52

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen oxides, Ozone, Particulate matter, Sulfur dioxide.

40 CFR Part 75

Environmental protection, Administrative practice and procedure, Air pollution control, Continuous emission monitoring, Electric power plants, Incorporation by reference, Nitrogen oxides, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 78

Environmental protection, Administrative practice and procedure, Air pollution control, Electric power plants, Nitrogen oxides, Ozone, Particulate matter, Sulfur dioxide.

40 CFR Part 97

Environmental protection, Administrative practice and procedure, Air pollution control, Electric power plants, Nitrogen oxides, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide.

Michael Regan,

Administrator.

For the reasons stated in the preamble, parts 52, 75, 78, and 97 of title 40 of the Code of Federal Regulations are proposed to be amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

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

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 2. Amend § 52.38 by:

■ a. In paragraph (a)(1), removing ''(NO_X), except'' and adding in its place ''(NO_X) for sources meeting the applicability criteria set forth in that subpart, except'';

■ b. In paragraph (a)(4) introductory text, removing ''State's sources, and'' and adding in its place ''State, and'';

■ c. In table 1 to paragraph (a)(4)(i)(B), revising the entry for ''2025 and any year thereafter'';

■ d. In paragraph (a)(5) introductory text, removing ''State (but not sources in any Indian country within the borders of the State), regulations'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations'';

■ e. In table 2 to paragraph (a)(5)(i)(B), revising the entry for ''2025 and any year thereafter'';

■ f. In paragraph (a)(5)(iv), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';

■ g. In paragraph (a)(5)(v), removing ''Indian country within the borders of the State, the'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority, the'';

■ h. Revising paragraphs (a)(6) and (a)(7)(ii);

■ i. In paragraph (a)(8)(iii), removing ''State (but not sources in any Indian country within the borders of the State):'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority:'';

■ j. In paragraph (b)(1), removing ''year), except'' and adding in its place ''year) for sources meeting the applicability criteria set forth in those subparts, except'';

■ k. Redesignating paragraphs (b)(2)(i) and (ii)as paragraphs (b)(2)(i)(A) and (B), respectively, redesignating paragraphs (b)(2)(iii) and (iv) as paragraphs (b)(2)(ii)(A) and (B), respectively, and redesignating paragraph (b)(2)(v) as paragraph (b)(2)(iii)(A);

■ l. In newly redesignated paragraph (b)(2)(ii)(A), removing ''Alabama, Arkansas, Iowa, Kansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin.'' and adding in its place ''Iowa and Kansas.'';

■ m. Adding paragraphs (b)(2)(ii)(C) and (b)(2)(iii)(B) and (C);

■ n. In paragraph (b)(3) introductory text, removing ''or (ii)'';

■ o. Revising paragraph (b)(4) introductory text;

■ p. In table 3 to paragraph (b)(4)(ii)(B), revising the entry for ''2025 and any year thereafter'';

■ q. Revising paragraph (b)(5) introductory text;

■ r. In table 4 to paragraph (b)(5)(ii)(B), revising the entry for ''2025 and any year thereafter'';

■ s. In paragraph (b)(5)(v), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';

■ t. In paragraph (b)(5)(vi), removing ''Indian country within the borders of the State, the'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority, the'';

■ u. In paragraph (b)(7) introductory text, removing ''(b)(2)(iii) or (iv)'' and adding in its place ''(b)(2)(ii)'';

■ v. Revising paragraph (b)(8) introductory text;

■ w. In paragraph (b)(8)(i), adding ''and'' after the semicolon;

■ x. Removing and reserving paragraph (b)(8)(ii);

■ y. Revising paragraph (b)(8)(iii)(A);

■ z. In table 5 to paragraph (b)(8)(iii)(B), revising the entry for ''2025 and any year thereafter'';

■ aa. In paragraph (b)(8)(iv), removing ''(b)(8)(i), (ii), or (iii)'' and adding in its place ''(b)(8)(i) or (iii)'' each time it appears;

■ bb. Revising paragraph (b)(9) introductory text;

■ cc. Removing and reserving paragraph (b)(9)(ii);

■ dd. Revising paragraph (b)(9)(iii)(A);

■ ee. In table 6 to paragraph (b)(9)(iii)(B), revising the entry for ''2025 and any year thereafter'';

■ ff. In paragraph (b)(9)(vi), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';

■ gg. Revising paragraph (b)(9)(vii);

■ hh. In paragraph (b)(9)(viii), removing ''(b)(9)(i), (ii), or (iii)'' and adding in its place ''(b)(9)(i) or (iii)'';

■ ii. Revising paragraphs (b)(10) introductory text, (b)(10)(i) and (ii), (b)(10)(v)(A) and (B), (b)(11) introductory text, (b)(11)(iii) introductory text, (b)(11)(iii)(A) introductory text, and (b)(11)(iii)(B);

■ jj. Removing and reserving paragraph (b)(11)(iii)(C);

■ kk. Revising paragraph (b)(11)(iii)(D);

■ ll. In paragraph (b)(11)(iv), removing ''paragraphs (b)(11)(iii)(B) and (C)'' and adding in its place ''paragraph (b)(11)(iii)(B)'';

■ mm. Revising paragraphs (b)(12) introductory text, (b)(12)(iii) introductory text, (b)(12)(iii)(A) introductory text, and (b)(12)(iii)(B);

■ nn. Removing and reserving paragraph (b)(12)(iii)(C);

■ oo. Revising paragraphs (b)(12)(iii)(D) and (b)(12)(vi) and (vii);

■ pp. In paragraph (b)(12)(viii), removing ''paragraphs (b)(12)(iii)(B) and (C)'' and adding in its place ''paragraph (b)(12)(iii)(B)'';

■ qq. Revising paragraphs (b)(13) introductory text and (b)(13)(i);
■ rr. In paragraph (b)(13)(ii), removing ''(b)(9)(ii) or'';
■ ss. In paragraph (b)(14)(i)(F), removing ''§ 97.825(b)'' and adding in its place ''§§ 97.806(c)(2) and (3) and 97.825(b)'';
■ tt. In paragraph (b)(14)(i)(G), removing ''§ 97.826(e)'' and adding in its place ''§ 97.826(f)'';
■ uu. Revising paragraphs (b)(14)(ii) and (b)(14)(iii) introductory text;
■ vv. In paragraph (b)(14)(iii)(D), removing ''and'' after the semicolon;
■ ww. In paragraph (b)(14)(iii)(E), removing ''(b)(2)(iv) of this section).'' and adding in its place ''(b)(2)(ii)(B) of this section);'';
■ xx. Adding paragraphs (b)(14)(iii)(F) and (G);
■ yy. In paragraph (b)(15)(iii), removing ''State (but not sources in any Indian country within the borders of the State):'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority:'';
■ zz. In paragraph (b)(16)(i)(B), removing ''§ 97.804(a) and (b) or'';
■ aaa. Revising paragraph (b)(16)(i)(C);
■ bbb. Redesignating paragraph (b)(16)(ii) as paragraph (b)(16)(ii)(A), and in the newly redesignated paragraph, removing ''(b)(2)(iv)'' and adding in its place ''(b)(2)(ii)(B)'';
■ ccc. Adding paragraph (b)(16)(ii)(B); and
■ ddd. Revising paragraphs (b)(17)(i) through (iii).

The revisions and additions read as follows:

§ 52.38 What are the requirements of the Federal Implementation Plans (FIPs) for the Cross-State Air Pollution Rule (CSAPR) relating to emissions of nitrogen oxides?

(a) * * *

(4) * * *

(i) * * *

(B) * * *

TABLE 1 TO PARAGRAPH (a)(4)(i)(B)

Year of the control period for which CSAPR NO_X annual allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * *	* * * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(5) * * *

(i) * * *

(B) * * *

TABLE 2 TO PARAGRAPH (a)(5)(i)(B)

Year of the control period for which CSAPR NO_X annual allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * *	* * * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(6) *Withdrawal of CSAPR FIP provisions relating to NO_X annual emissions.* Except as provided in paragraph (a)(7) of this section, following promulgation of an approval by the Administrator of a State's SIP revision as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (a)(1), (a)(2)(i), and (a)(3) and (4) of this section for sources in the State and Indian country within the borders of the State, the provisions of paragraph (a)(2)(i) of this section will no longer apply to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in areas of Indian country within the borders of the State not subject to the State's SIP authority, provided that if the CSAPR Federal Implementation Plan was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(7) * * *

(ii) Notwithstanding the provisions of paragraph (a)(6) of this section, if, at the time of any approval of a State's SIP revision under this section, the Administrator has already started recording any allocations of CSAPR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

* * * * *

(b) * * *

(2) * * *

(ii) * * *

(C) The provisions of subpart EEEEE of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States with regard to emissions occurring in 2017 through 2022 only, except as provided in paragraph (b)(14)(iii) of this section: Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin.

(iii) * * *

(B) The provisions of subpart GGGGG of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States with regard to emissions occurring in 2023 and each subsequent year: Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin.

(C) The provisions of subpart GGGGG of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States with regard to emissions occurring on and after [EFFECTIVE DATE OF FINAL RULE] and in each subsequent year: Delaware, Minnesota, Nevada, Utah, and Wyoming.

* * * * *

(4) *Abbreviated SIP revisions replacing certain provisions of the federal CSAPR NO_X Ozone Season Group 1 Trading Program.* A State listed in paragraph (b)(2)(i)(A) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations replacing specified provisions of subpart BBBBB of part 97 of this chapter for the State, and not substantively replacing any other provisions, as follows:

* * * * *

(ii) * * *

(B) * * *

TABLE 3 TO PARAGRAPH (b)(4)(ii)(B)

Year of the control period for which CSAPR NO_X ozone season Group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * * *	* * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(5) *Full SIP revisions adopting State CSAPR NO_X Ozone Season Group 1 Trading Programs.* A State listed in paragraph (b)(2)(i)(A) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(i), and (b)(3) and (4) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations that are substantively identical to the provisions of the CSAPR NO_X Ozone Season Group 1 Trading Program set forth in §§ 97.502 through 97.535 of this chapter, except that the SIP revision:

* * * * *

(ii) * * *

(B) * * *

TABLE 4 TO PARAGRAPH (b)(5)(ii)(B)

Year of the control period for which CSAPR NO_X ozone season Group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * * *	* * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(8) *Abbreviated SIP revisions replacing certain provisions of the federal CSAPR NO_X Ozone Season Group 2 Trading Program.* A State listed in paragraph (b)(2)(ii) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations replacing specified provisions of subpart EEEEE of part 97 of this chapter for the State, and not substantively replacing any other provisions, as follows:

* * * * *

(iii) * * *

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 2 allowances for any such control period not exceeding the amount, under §§ 97.810(a) and 97.821 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 2 trading budget minus the sum of the Indian country new unit set-aside and the amount of any CSAPR NO_X Ozone Season Group 2 allowances already allocated and recorded by the Administrator;

(B) * * *

TABLE 5 TO PARAGRAPH (b)(8)(iii)(B)

Year of the control period for which CSAPR NO_X ozone season Group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * * *	* * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(9) *Full SIP revisions adopting State CSAPR NO_X Ozone Season Group 2 Trading Programs.* A State listed in paragraph (b)(2)(ii) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(ii), and (b)(7) and (8) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations that are substantively identical to the provisions of the CSAPR NO_X Ozone Season Group 2 Trading Program set forth in §§ 97.802 through 97.835 of this chapter, except that the SIP revision:

* * * * *

(iii) * * *

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 2 allowances for any such control period not exceeding the amount, under

§§ 97.810(a) and 97.821 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 2 trading budget minus the sum of the Indian country new unit set-aside and the amount of any CSAPR NO_X Ozone Season Group 2 allowances already allocated and recorded by the Administrator;

(B) * * *

TABLE 6 TO PARAGRAPH (b)(9)(iii)(B)

Year of the control period for which CSAPR NO_X ozone season Group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * *	* * * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(vii) Provided that, if and when any covered unit is located in areas of Indian country within the borders of the State not subject to the State's SIP authority, the Administrator may modify his or her approval of the SIP revision to exclude the provisions in §§ 97.802 (definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.806(c)(2), and 97.825 of this chapter and the portions of other provisions of subpart EEEEE of part 97 of this chapter referencing these sections and may modify any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions; and

* * * * *

(10) *State-determined allocations of CSAPR NO_X Ozone Season Group 3 allowances for 2024.* A State listed in paragraph (b)(2)(iii) of this section may adopt and include in a SIP revision, and the Administrator will approve, as CSAPR NO_X Ozone Season Group 3 allowance allocation provisions replacing the provisions in § 97.1011(a)(1) of this chapter with regard to the State and the control period in 2024, a list of CSAPR NO_X Ozone Season Group 3 units and the amount of CSAPR NO_X Ozone Season Group 3 allowances allocated to each unit on such list, provided that the list of units and allocations meets the following requirements:

(i) All of the units on the list must be units that are in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and that commenced commercial operation before January 1, 2021;

(ii) The total amount of CSAPR NO_X Ozone Season Group 3 allowance allocations on the list must not exceed the amount, under § 97.1010 of this chapter for the State and the control period in 2024, of the CSAPR NO_X Ozone Season Group 3 trading budget minus the sum of the new unit set-aside and Indian country existing unit set-aside;

* * * * *

(v) * * *

(A) By [EFFECTIVE DATE OF FINAL RULE], the State must notify the Administrator electronically in a format specified by the Administrator of the State's intent to submit to the Administrator a complete SIP revision meeting the requirements of paragraphs (b)(10)(i) through (iv) of this section by September 1, 2023; and

(B) The State must submit to the Administrator a complete SIP revision described in paragraph (b)(10)(v)(A) of this section by September 1, 2023.

(11) *Abbreviated SIP revisions replacing certain provisions of the federal CSAPR NO_X Ozone Season Group 3 Trading Program.* A State listed in paragraph (b)(2)(iii) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations replacing specified provisions of subpart GGGGG of part 97 of this chapter for the State, and not substantively replacing any other provisions, as follows:

* * * * *

(iii) The State may adopt, as CSAPR NO_X Ozone Season Group 3 allowance allocation or auction provisions replacing the provisions in § 97.1011(a)(1) of this chapter with regard to the State and the control period in 2025 or any subsequent year, any methodology under which the State or the permitting authority allocates or auctions CSAPR NO_X Ozone Season Group 3 allowances and may adopt, in addition to the definitions in § 97.1002 of this chapter, one or more definitions that shall apply only to terms as used in the adopted CSAPR NO_X Ozone Season Group 3 allowance allocation or auction provisions, if such methodology—

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 3 allowances for any such control period not exceeding the amount, under §§ 97.1010 and 97.1021 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 3 trading budget minus the sum of the new unit set-aside, the Indian country existing unit set-aside, and the amount of any CSAPR NO_X Ozone Season Group 3 allowances already allocated and recorded by the Administrator, plus, if the State adopts regulations expanding applicability to additional units pursuant to paragraph (b)(11)(ii) of this section, an additional amount of CSAPR NO_X Ozone Season Group 3 allowances not exceeding the lesser of:

* * * * *

(B) Requires, to the extent the State adopts provisions for allocations or auctions of CSAPR NO_X Ozone Season Group 3 allowances for any such control period to any CSAPR NO_X Ozone Season Group 3 units covered by § 97.1011(a)(1) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions for such control period (except allocations or results of auctions to such units of CSAPR NO_X Ozone Season Group 3 allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator by June 1 of the year before the year of such control period; and

* * * * *

(D) Does not provide for any change, after the submission deadlines in paragraph (b)(11)(iii)(B) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart GGGGG of part 97 of this chapter or § 97.526(d) or § 97.826(d) or (e) of this chapter;

* * * * *

(12) *Full SIP revisions adopting State CSAPR NO_X Ozone Season Group 3 Trading Programs.* A State listed in paragraph (b)(2)(iii) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal

Implementation Plan set forth in paragraphs (b)(1), (b)(2)(iii), and (b)(10) and (11) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations that are substantively identical to the provisions of the CSAPR NO_X Ozone Season Group 3 Trading Program set forth in §§ 97.1002 through 97.1035 of this chapter, except that the SIP revision:

* * * * *

(iii) May adopt, as CSAPR NO_X Ozone Season Group 3 allowance allocation provisions replacing the provisions in § 97.1011(a)(1) of this chapter with regard to the State and the control period in 2025 or any subsequent year, any methodology under which the State or the permitting authority allocates or auctions CSAPR NO_X Ozone Season Group 3 allowances and that—

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 3 allowances for any such control period not exceeding the amount, under §§ 97.1010 and 97.1021 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 3 trading budget minus the sum of the new unit set-aside, the Indian country existing unit set-aside, and the amount of any CSAPR NO_X Ozone Season Group 3 allowances already allocated and recorded by the Administrator, plus, if the State adopts regulations expanding applicability to additional units pursuant to paragraph (b)(12)(ii) of this section, an additional amount of CSAPR NO_X Ozone Season Group 3 allowances not exceeding the lesser of:

* * * * *

(B) Requires, to the extent the State adopts provisions for allocations or auctions of CSAPR NO_X Ozone Season Group 3 allowances for any such control period to any CSAPR NO_X Ozone Season Group 3 units covered by § 97.1011(a)(1) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions for such control period (except allocations or results of auctions to such units of CSAPR NO_X Ozone Season Group 3 allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator by June 1 of the year before the year of such control period; and

* * * * *

(D) Does not provide for any change, after the submission deadlines in paragraph (b)(12)(iii)(B) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart GGGGG of part 97 of this chapter or § 97.526(d) or § 97.826(d) or (e) of this chapter;

* * * * *

(vi) Must not include any of the requirements imposed on any unit in areas of Indian country within the borders of the State not subject to the State's SIP authority in the provisions in §§ 97.1002 through 97.1035 of this chapter and must not include the provisions in §§ 97.1011(a)(2), 97.1012, and 97.1021(g) through (j) of this chapter, all of which provisions will continue to apply under the portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision;

(vii) Provided that, if any covered unit is located in areas of Indian country within the borders of the State not subject to the State's SIP authority before the Administrator's approval of the SIP revision, the SIP revision must exclude the provisions in §§ 97.1002 (definitions of ''base CSAPR NO_X Ozone Season Group 3 source'', ''base CSAPR NO_X Ozone Season Group 3 unit'', ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.1006(c)(2), and 97.1025 of this chapter and the portions of other provisions of subpart GGGGG of part 97 of this chapter referencing these sections, and further provided that, if and when any covered unit is located in areas of Indian country within the borders of the State not subject to the State's SIP authority after the Administrator's approval of the SIP revision, the Administrator may modify his or her approval of the SIP revision to exclude these provisions and may modify any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions; and

* * * * *

(13) *Withdrawal of CSAPR FIP provisions relating to NO_X ozone season emissions; satisfaction of NO_X SIP Call requirements.* Following promulgation of an approval by the Administrator of a State's SIP revision as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(i), and (b)(3) and (4) of this section, paragraphs (b)(1), (b)(2)(ii), and (b)(7) and (8) of this section, or paragraphs (b)(1), (b)(2)(iii), and (b)(10) and (11) of this section for sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority—

(i) Except as provided in paragraph (b)(14) of this section, the provisions of paragraph (b)(2)(i), (ii), or (iii) of this section, as applicable, will no longer apply to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in areas of Indian country within the borders of the State not subject to the State's SIP authority, provided that if the CSAPR Federal Implementation Plan was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision; and

* * * * *

(14) * * *

(ii) Notwithstanding the provisions of paragraph (b)(13)(i) of this section, if, at the time of any approval of a State's SIP revision under this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 1 allowances under subpart BBBBB of part 97 of this chapter, or allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter, or allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter, to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(iii) Notwithstanding any discontinuation of the applicability of subpart BBBBB or EEEEE of part 97 of this chapter to the sources in a State and areas of Indian country within the borders of the State subject to the State's SIP authority with regard to emissions occurring in any control period pursuant to paragraph (b)(2)(i)(B), (b)(2)(ii)(B) or (C), or (b)(13)(i) of this section, the following provisions shall continue to apply with regard to all CSAPR NO_X Ozone Season Group 1 allowances and CSAPR NO_X Ozone Season Group 2 allowances at any time allocated for any control period to any source or other entity in the State and shall apply to all entities, wherever located, that at any time held or hold such allowances:

* * * * *

(F) The provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances); and

(G) The provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods after 2022 and recorded in the compliance accounts of sources in States listed in paragraph (b)(2)(ii)(C) of this section).

* * * * *

(16) * * *

(i) * * *

(C) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(9) of this section as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(ii), and (b)(7) and (8) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority: Alabama, Indiana, and Missouri.

(ii) * * *

(B) Notwithstanding any provision of subpart EEEEE of part 97 of this chapter or any State's SIP, with regard to any State listed in paragraph (b)(2)(ii)(C) of this section and any control period that begins after December 31, 2022, the Administrator will not carry out any of the functions set forth for the Administrator in subpart EEEEE of part 97 of this chapter, except §§ 97.811(e) and 97.826(c) and (e) of this chapter, or in any emissions trading program provisions in a State's SIP approved under paragraph (b)(8) or (9) of this section.

(17) * * *

(i) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(10) of this section as replacing the CSAPR NO_X Ozone Season Group 3 allowance allocation provisions in § 97.1011(a)(1) of this chapter with regard to the State and the control period in 2024: [none].

(ii) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(11) of this section as replacing the CSAPR NO_X Ozone Season Group 3 applicability provisions in § 97.1004(a) and (b) or § 97.1004(a)(1) and (2) of this chapter or the CSAPR NO_X Ozone Season Group 2 allowance allocation provisions in § 97.1011(a)(1) of this chapter with regard to the State and the control period in 2025 or any subsequent year: [none].

(iii) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(12) of this section as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(iii), and (b)(10) and (11) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority: [none].

■ 3. Amend § 52.39 by:

■ a. In paragraph (a), removing "(SO_2), except" and adding in its place "(SO_2) for sources meeting the applicability criteria set forth in those subparts, except";

■ b. In paragraph (e) introductory text, removing "State's sources, and" and adding in its place "State, and";

■ c. In table 1 to paragraph (e)(1)(ii), revising the entry for "2025 and any year thereafter";

■ d. In paragraph (f) introductory text, removing "State (but not sources in any Indian country within the borders of the State), regulations" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations";

■ e. In table 2 to paragraph (f)(1)(ii), revising the entry for "2025 and any year thereafter";

■ f. In paragraph (f)(4), removing "Indian country within the borders of the State" and adding in its place "areas of Indian country within the borders of the State not subject to the State's SIP authority";

■ g. In paragraph (f)(5), removing "Indian country within the borders of the State, the" and adding in its place "areas of Indian country within the borders of the State not subject to the State's SIP authority, the";

■ h. In paragraph (h) introductory text, removing "State's sources, and" and adding in its place "State, and";

■ i. In table 3 to paragraph (h)(1)(ii), revising the entry for "2025 and any year thereafter";

■ j. In paragraph (i) introductory text, removing "State (but not sources in any Indian country within the borders of the State), regulations" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations";

■ k. In table 4 to paragraph (i)(1)(ii), revising the entry for "2025 and any year thereafter";

■ l. In paragraph (i)(4), removing "Indian country within the borders of the State" and adding in its place "areas of Indian country within the borders of the State not subject to the State's SIP authority";

■ m. In paragraph (i)(5), removing "Indian country within the borders of the State, the" and adding in its place "areas of Indian country within the borders of the State not subject to the State's SIP authority, the";

■ n. Revising paragraphs (j) and (k)(2); and

■ o. In paragraphs (l)(3) and (m)(3), removing "State (but not sources in any Indian country within the borders of the State):" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority:".

The revisions read as follows:

§ 52.39 What are the requirements of the Federal Implementation Plans (FIPs) for the Cross-State Air Pollution Rule (CSAPR) relating to emissions of sulfur dioxide?

* * * * *

(e) * * *

(1) * * *

(ii) * * *

TABLE 1 TO PARAGRAPH (e)(1)(ii)

Year of the control period for which CSAPR SO_2 Group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * *	* * * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(f) * * *

(i) * * *

(ii) * * *

TABLE 2 TO PARAGRAPH (f)(1)(ii)

Year of the control period for which CSAPR SO_2 Group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * * *	* * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(h) * * *

(1) * * *

(ii) * * *

TABLE 3 TO PARAGRAPH (h)(1)(ii)

Year of the control period for which CSAPR SO_2 Group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * * *	* * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(i) * * *

(1) * * *

(ii) * * *

TABLE 4 TO PARAGRAPH (i)(1)(ii)

Year of the control period for which CSAPR SO_2 Group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * * *	* * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(j) *Withdrawal of CSAPR FIP provisions relating to SO_2 emissions.* Except as provided in paragraph (k) of this section, following promulgation of an approval by the Administrator of a State's SIP revision as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (a), (b), (d), and (e) of this section or paragraphs (a), (c)(1), (g), and (h) of this section for sources in the State and Indian country within the borders of the State, the provisions of paragraph (b) or (c)(1) of this section, as applicable, will no longer apply to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in areas of Indian country within the borders of the State not subject to the State's SIP authority, provided that if the CSAPR Federal Implementation Plan was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(k) * * *

(2) Notwithstanding the provisions of paragraph (j) of this section, if, at the time of any approval of a State's SIP revision under this section, the Administrator has already started recording any allocations of CSAPR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter, or allocations of CSAPR SO_2 Group 2 allowances under subpart DDDDD of part 97 of this chapter, to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

* * * * *

■ 4. Add §§ 52.40 through 52.45 to read as follows:

* * * * *

52.44 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Glass and Glass Product Manufacturing Industry?

52.45 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills Industries?

* * * * *

§ 52.40 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from sources not subject to the CSAPR ozone season trading program?

(a) *NO_X ozone season emissions.* This section establishes Federal Implementation Plan requirements for new and existing units in the industries specified in paragraph (b) of this section to eliminate significant contribution to nonattainment, or interference with maintenance, of the 2015 8-hour ozone National Ambient Air Quality Standards in other states pursuant to 42 U.S.C. 7410(a)(2)(D)(i)(I).

(b) *General requirements* (1) The NO_X emissions limitations and associated compliance requirements for the following listed source categories not subject to the CSAPR ozone season trading program constitute the 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): § 52.41 for engines in the Pipeline Transportation of Natural Gas Industry, § 52.42 for kilns in the Cement and Concrete Product Manufacturing Industry, § 52.43 for units in the Iron and Steel Mills and Ferroalloy Manufacturing Industry, § 52.44 for units in the Glass and Glass Product Manufacturing Industry, § 52.45 for boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.

(2) The provisions of §§ 52.41 through 52.45 of this part apply to sources located in each of the following States, including Indian country located within the borders of such States, beginning in the 2026 ozone season and in each subsequent ozone season: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming.

(3) The owner or operator of an affected unit subject to the provisions of §§ 52.40 through 52.45 shall maintain files of all information (including all reports and notifications) required by these sections recorded in a form suitable and readily available for expeditious inspection and review. The files shall be retained for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent 2 years of data shall be retained on site. The remaining 3 years of data may be retained off site. Such files may be maintained on microfilm, on a computer, on computer floppy disks, on magnetic tape disks, or on microfiche.

§ 52.41 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Pipeline Transportation of Natural Gas Industry?

(a) *Definitions.* All terms not defined herein shall have the meaning given them in the Act and in subpart A of part 60.

Affected unit means an engine meeting the applicability criteria of this section.

Four stroke means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity and 101.3 kilopascals pressure.

Lean burn means any two-stroke or four-stroke spark ignited reciprocating internal combustion engine that does not meet the definition of a rich burn engine.

Nameplate rating means the manufacturer's design maximum capacity in horsepower (hp) at the installation site conditions. Starting from the completion of any physical change in the engine resulting in an increase in the maximum output (in hp) that the engine is capable of producing on a steady state basis and during continuous operation, such increased maximum output shall be as specified by the person conducting the physical change.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane) or non-hydrocarbons, composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Natural gas-fired means that greater than or equal to 90% of the engine's heat input, excluding recirculated or recuperated exhaust heat, is derived from the combustion of natural gas.

Operator means any person who operates, controls, or supervises a natural gas-fired engine subject to this regulation and shall include, but not be limited to, any holding company, utility system, or plant manager of such natural gas-fired engine.

Owner means any holder of any portion of the legal or equitable title in a natural gas-fired engine subject to this regulation.

Pipeline transportation of natural gas means the movement of natural gas through an interconnected network of compressors and pipeline components, from field gathering networks near wellheads to end users, including:

(i) The compressor and pipeline network used for field gathering of natural gas from the wellheads for delivery to either processing facilities or connections to pipelines used for intrastate or interstate transportation of the natural gas; and

(ii) The compressor and pipeline network used to transport the natural gas from field gathering networks or processing facilities over a distance (intrastate or interstate) to and from storage facilities, to large natural gas end-users, and to distribution organizations that provide the natural gas to end-users.

Reciprocating internal combustion engine means a reciprocating engine in which power, produced by heat and/or pressure that is developed in the engine combustion chambers by the burning of a mixture of air and fuel, is subsequently converted to mechanical work.

Rich burn means any four-stroke spark ignited reciprocating internal combustion engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Internal combustion engines originally manufactured as rich burn engines but modified with passive emission control technology for nitrogen oxides (NO_X) (such as pre-combustion chambers) will be considered lean burn engines. Existing internal combustion engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered rich burn engines if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Spark ignition means a reciprocating internal combustion engine utilizing a spark plug (or other sparking device) to ignite the air/fuel mixture and with operating characteristics significantly similar to the theoretical Otto combustion cycle.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Two stroke means a type of reciprocating internal combustion engine which completes the power cycle in a single crankshaft revolution by combining the intake and compression operations into one stroke (one-half revolution) and the power and exhaust operations into a second stroke. This system requires auxiliary exhaust scavenging of the combustion products and inherently runs lean (excess of air) of stoichiometry.

(b) *Applicability.* You are subject to the requirements under this section if you own or operate a new or existing natural gas-fired spark ignition engine with a nameplate rating of 1,000 hp or greater that is used for pipeline transportation of natural gas and is located within any of the States listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such State(s).

(c) *Emissions limitations.* Beginning with the 2026 ozone season and in each ozone season thereafter, the following emissions limitations must be met. Compliance with the numerical emissions limitations established in this section is based on the average of three 1-hour runs using the testing requirements and procedures in paragraph (d) of this section.

(1) If you own or operate a natural gas fired four stroke rich burn spark ignition engine with a nameplate rating of 1,000 hp or greater than you must meet a nitrogen oxides (NO_X) emissions limits of 1.0 grams per hp-hour (g/hp-hr).

(2) If you own or operate a natural gas fired four stroke lean burn spark ignition engine with a nameplate rating of 1,000 hp or greater than you must meet a NO_X emissions limits of 1.5 g/hp-hr.

(3) If you own or operate a natural gas fired two stroke lean spark ignition engine with a nameplate rating of 1,000 hp or greater than you must meet a NO_X emissions limits of 3.0 g/hp-hr.

(d) *Testing and monitoring requirements* (1) If you are an owner or operator of a natural gas fired spark ignition engine subject to a NO_X emissions limit under paragraph (b) of this section, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions.

(2) Performance Testing Requirements:

(i) Engines that meet the certification requirements of § 60.4243(a) need not conduct any performance tests, consistent with the requirements of 40 CFR part 60, subpart JJJJ.

(ii) For non-certified engines, the following performance testing requirements apply:

(A) New engines must conduct an initial performance test within six months of engine startup and conduct subsequent performance testing every six months thereafter to demonstrate compliance.

(B) Existing engines must conduct an initial performance test within six months of becoming subject to an emissions limit under paragraph (b) of this section and conduct subsequent performance testing every six months thereafter to demonstrate compliance.

(iii) Performance tests must be conducted in accordance with the applicable reference test methods of 40 CFR part 60, appendix A, any alternative test method approved by EPA as of April 6, 2022 under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii), or 65.158(a)(2) and available at EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by EPA through notice-and-comment rulemaking.

(3) If a selective catalytic reduction (SCR) or non-selective catalytic reduction (NSCR) control device is used to reduce emissions:

(i) Monitor the inlet temperature to the catalyst daily and conduct maintenance if the temperature is not within the observed inlet temperature range from the most recent performance test or the temperatures specified by the manufacturer if no performance test was required by this section.

(ii) Measure the pressure drop across the catalyst monthly and conduct maintenance if the pressure drop is greater than 2 inches outside the baseline value established after each semiannual portable analyzer monitoring.

(iii) Engines that are subject to catalyst temperatures and catalyst pressure drop monitoring requirements under 40 CFR part 63, subpart ZZZZ must satisfy the requirements of § 52.41(d)(3).

(4) If you are not using a SCR or NSCR control device to reduce emissions are required to install a continuous parameter monitoring system (CPMS). You must install, operate, and maintain each CPMS according to the requirements in paragraphs (d)(4)(i) through (vi) of this section.

(i) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and quality assurance and quality control elements outlined in paragraphs (d)(4)(i)(A) through (E) of this section.

(A) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(B) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements.

(C) Equipment performance evaluations, system accuracy audits, or other audit procedures.

(D) Ongoing operation and maintenance procedures in accordance with the requirements of paragraph (d)(1) of this section.

(E) Ongoing recordkeeping and reporting procedures in accordance with the requirements of paragraphs (e) and (f) of this section.

(ii) Install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(iii) The CPMS must collect data at least once every 15 minutes.

(iv) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(v) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(vi) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(e) *Recordkeeping requirements* (1) You must keep records of:

(i) Performance tests conducted pursuant to § 52.41(d)(2), including the date, engine settings on the date of the test, and documentation of the methods and results of the testing.

(ii) Catalyst monitoring required by § 52.41(d)(3), if applicable, and any actions taken to address monitored values outside the temperature or pressure drop parameters, including the date and a description of actions taken.

(iii) Parameters monitored pursuant to your site-specific monitoring plan for your CPMS.

(iv) Hours of operation on a daily basis.

(v) Tuning, adjustments, or other combustion process adjustments and the date of the adjustment(s).

(2) Any records required to be maintained by this section that are submitted electronically via the EPA's Compliance and Emissions Data Reporting Interface (CEDRI) may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the EPA as part of an on-site compliance evaluation.

(f) *Reporting requirements* (1) Within 60 days after the date of completing each performance test required by this section, you must submit the results of the performance test following the procedures specified in paragraphs (f)(1)(i) through (iii):

(i) *Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.* Submit the results of the performance test to the EPA via the CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website.

(ii) *Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.* The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(iii) *Confidential business information (CBI). Do not use CEDRI to submit information you claim as CBI.* Anything submitted using CEDRI cannot later be claimed CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraphs (f)(1)(i) or (ii) of this section, you must submit a complete file, including information claimed to be CBI, to the EPA. The file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in paragraphs (f)(1)(i) and (ii). All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(2) If you are the owner or operator of an affected engine, you shall submit a semi-annual report, at least every six months, in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. The report shall contain the following information:

(i) The name and address of the owner and operator;

(ii) The address of the subject engine;

(iii) Longitude and latitude coordinates of the subject engine;

(iv) Identification of the subject engine;

(v) Statement of compliance with the applicable emission limit under § 52.41(b);

(vi) Statement of compliance regarding the conduct of maintenance and operations in a manner consistent with good air pollution control practices for minimizing emissions;

(vii) The date and results of the performance test conducted pursuant to § 52.41(d);

(viii) If applicable, a statement documenting any change in the operating characteristics of the subject engine; and

(ix) A statement certifying that the information included in the semi-annual report is complete and accurate.

(3) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (f)(3)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(4) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (f)(4)(i) through (v) of this section.

(i) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(iv) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

§ 52.42 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Cement and Concrete Product Manufacturing Industry?

(a) *Definitions.* All terms not defined herein shall have the meaning given them in the Act and in subpart A of part 60.

Affected unit means a cement kiln meeting the applicability criteria of this section.

Cement plant means any facility manufacturing cement by either the wet or dry process.

Clinker means the product of a cement kiln from which finished cement is manufactured by milling and grinding.

Cement kiln means an installation, including any associated pre-heater or pre-calciner devices, that produces clinker by heating limestone and other materials to produce Portland cement.

Operating day means a 24-hour period beginning at 12:00 midnight during which the kiln produces clinker at any time.

Rolling average means the weighted average of all data, meeting QA/QC requirements or otherwise normalized, collected during the applicable averaging period. The period of a rolling average stipulates the frequency of data averaging and reporting. To demonstrate compliance with an operating parameter a 30-day rolling average period requires calculation of a new average value each operating day and shall include the average of all the hourly averages of the specific operating parameter. For demonstration of compliance with an emissions limit based on pollutant concentration, a 30-day rolling average is comprised of the average of all the hourly average concentrations over the previous 30 operating days. For demonstration of compliance with an emissions limit based on lbs-pollutant per production unit, the 30-day rolling average is calculated by summing the hourly mass emissions over the previous 30 operating days, then dividing that sum by the total production during the same period.

(b) *Applicability.* You are subject to the requirements of this section if you own or operate a new or existing cement kiln that emits or has the potential to emit 100 tons per year or more of NO_X and is located within any of the States listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such State(s).

(c) Emission limitations (1) If you own or operate a cement kiln under paragraph (b) of this section you are subject to the NO_X emissions limits in the following table and the NO_X source cap limit under paragraph (c)(2) of this section, beginning with the 2026 ozone season and in each ozone season thereafter.

TABLE 1 TO PARAGRAPH (c)(1)

Kiln type	Proposed NO_X emissions limit (lb/ton of clinker)
Long Wet	4.0
Long Dry	3.0
Preheater	3.8
Precalciner	2.3
Preheater/Precalciner	2.8

(2) The NO_X source cap limit is calculated in accordance with the following equation:

$$CAP2015\ Ozone\ Transport = \frac{(KW\ x\ NW) + (KD\ x\ ND)}{\left(2000\,\frac{pounds}{ton}\ x\ 365\,\frac{days}{year}\right)}$$

Where:

CAP2015 Ozone Transport = total allowable NO_X emissions from all cement kilns located at one cement plant, in tons per day, on a 30-operating day rolling average basis;

KD = 1.7 pounds NO_X per ton of clinker for dry preheater-precalciner or precalciner kilns;

KW = 3.4 pounds NO_X per ton of clinker for long wet kilns;

ND = the average annual production in tons of clinker plus one standard deviation for the three most recent calendar years from all dry preheater-precalciner or precalciner kilns located at one cement plant; and

NW = the average annual production in tons of clinker plus one standard deviation for the three most recent calendar years from all long wet kilns located at one cement plant.

(d)*Testing and monitoring requirements* (1) If you own or operate a cement manufacturing plant subject to the NO_X emissions limits under paragraph (c) of this section you must conduct performance tests, on a semi-annual basis, in accordance with the applicable reference test methods of 40 CFR part 60, Appendix A, any alternative test method approved by EPA as of April 6, 2022 under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii), or 65.158(a)(2) and available at EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by EPA through notice-and-comment rulemaking. You must calculate and record the 30-operating day rolling emission rate of NO_X as the total of all hourly emissions data for a cement kiln in the preceding 30 days, divided by the total tons of clinker produced in that kiln during the same 30-operating day period using Equation 6 of 40 CFR 60.64(c)(1), shown in this equation:

$$E_{30\mathrm{D}} = \mathrm{k}\left(\frac{\sum_{i=1}^{n} Ci\ Qi}{P}\right)$$

Where:
E_{30D} = 30 kiln operating day average emission rate of NO_X, in lbs/ton of clinker.
Ci = Concentration of NO_X for hour i, in ppm.
Qi = Volumetric flow rate of effluent gas for hour i, where Ci and Qi are on the same basis (either wet or dry), in scf/hr.
P = 30 days of clinker production during the same time period as the NO_X emissions measured, in tons.
k = Conversion factor, 1.194×10^{-7} for NO_X, in lb/scf/ppm.
n = Number of kiln operating hours over 30 kiln operating days.

(e) Recordkeeping requirements (1) If you own or operate a cement manufacturing plant subject to the NO_X emissions limits under paragraph (c) of this section you must retain records of the calculations and measurements as required in paragraph (d) of this section for the 5-year period specified in 52.40(b)(3).

(2) Any records required to be maintained by this section that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the EPA as part of an on-site compliance evaluation.

(f) *Reporting requirements* (1) Within 60 days after the date of completing each performance test required by this section, you must submit the results of the performance test following the procedures specified in paragraphs (f)(1)(i) through (iii) of this section:

(i) *Data collected using test methods supported by the EPA's ERT as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.* Submit the results of the performance test to the EPA via the CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website.

(ii) *Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.* The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(iii) *CBI. Do not use CEDRI to submit information you claim as CBI.* Anything submitted using CEDRI cannot later be claimed CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraph (f)(1)(i) or (ii) of this section, you must submit a complete file, including information claimed to be CBI, to the EPA. The file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in paragraphs (f)(1)(i) and (ii) of this section. All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(2) If you are the owner or operator of an affected cement kiln, you shall submit a semi-annual, at least every six months, report in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section.

(3) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (f)(3)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(4) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (f)(4)(i) through (v) of this section.

(i) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(iv) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

§ 52.43 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Iron and Steel Mills and Ferroalloy Manufacturing Industry?

(a) *Definitions.* All terms not defined herein shall have the meaning given them in the Act and in subpart A of part 60.

Affected unit means any annealing furnace, basic oxygen process furnace, blast furnace, coke oven facility, electric arc furnace, ladle metallurgy furnace, ladle/tundish preheating system, reheat furnace, taconite production kiln, vacuum degasser, and industrial boiler meeting the applicability criteria of this section, and any such unit contained within a BOF Shop meeting the applicability criteria of this section.

Annealing furnace shall mean a furnace used to heat materials at very high temperatures to change their hardness and strength properties.

Basic Oxygen Process Furnace (BOF) shall mean a refractory-lined vessel in which high-purity oxygen is blown under pressure through a bath of molten iron, scrap metal, and fluxes to produce steel. This definition includes both top and bottom blown furnaces, but does not include argon oxygen decarburization furnaces.

Blast furnace means refractory-lined furnaces charged through its top with iron ore pellets (taconite), sinter, flux (limestone and dolomite), and coke in a reducing atmosphere to produce iron.

BOF Shop means the place where steel making operations occur, beginning with the transfer of molten iron (hot metal) from the torpedo car and ending just prior to casting the molten steel, including hot metal transfer, desulfurization, slag skimming, refining in a basic oxygen process furnace, and ladle metallurgy.

BOF Baghouse System means the control system for control of emissions from charging and tapping of the BOFs, including the capture hoods, ductwork and the BOF Baghouse.

Coke means carbon product that is formed by the thermal distillation of coal at high temperatures in the absence of air in coke oven batteries.

Coke Ovens means ovens producing coke for use in blast furnaces.

Day means a calendar day unless expressly stated to be a business day. In computing any period of time for recordkeeping and reporting purposes where the last day would fall on a Saturday, Sunday, or Federal holiday, the period shall run until the close of business of the next business day.

Electric Arc Furnace means a furnace equipped with electrodes used to produce carbon steels and alloy steels primarily by recycling ferrous scrap.

Exceedance means a reading in excess of an applicable opacity or emissions limitation.

Ladle Metallurgy Furnace means a furnace used to refine molten steel into specialty grades while keeping the steel in the ladle.

Ladle/Tundish Preheaters means equipment used to preheat ladles or tundishes to minimize temperature drop prior to use in iron or molten steel refinement.

Reheat Furnace means a furnace used to heat steel product to temperatures at which it will be suitable for deformation and further processing.

Steel Production Cycle means the operations conducted within the basic oxygen process furnace shop that are required to produce each batch of steel, including scrap charging, preheating, hot metal charging, primary oxygen blowing, sampling, (vessel turndown and turnup), additional oxygen blowing, tapping, and deslagging. The steel production cycle begins when the scrap is charged to the furnace and ends three minutes after the slag is emptied from the vessel into the slag pot.

Taconite production kiln means a furnace designed to dry and indurate taconite concentrates to create taconite pellets.

Vacuum degasser means a unit operated within an iron and steel facility to expose molten steel at low pressure to remove certain gases during steel refinement.

(b) *Applicability* The requirements of this section apply to each new or existing emissions unit at an iron and steel mill or ferroalloy manufacturing facility that directly emits or has the potential to emit 100 tons per year or more of NO_X, and to each BOF Shop containing two or more such units that collectively emit or have the potential to emit 100 tons per year or more of NO_X, and that is located within any of the States listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such State(s).

(c) *Emissions Limitations and Requirements.* Beginning with the 2026 ozone season and in each ozone season thereafter, the emissions limitations in the following table must be met on a 3-hour rolling average.

TABLE 1 TO PARAGRAPH (c)

Emission unit	NO_X Emissions standard or control requirement
Blast Furnace	0.03 lb/mmBtu.
Basic Oxygen Process Furnace	0.07 lb/ton steel.
Electric Arc Furnace	0.15 lb/ton steel.
Ladle/tundish Preheaters	0.06 lb/mmBtu.
Reheat furnace	0.05 lb/mmBtu.
Annealing Furnace	0.06 lb/mmBtu.
Vacuum Degasser	0.03 lb/mmBtu.
Ladle Metallurgy Furnace	0.1 lb/ton steel.
Taconite Production Kilns	Install and operate low NO_X burners as required by 2013 and 2016 Minnesota FIPs. 40 CFR § 52.1183.
Coke Ovens (charging)	0.15 lb/ton of coal charged.
Coke Oven push cars and pushing-charging machines (pushing)	0.015 lb/ton of coal pushed.

TABLE 1 TO PARAGRAPH (c)—Continued

Emission unit	NO_X Emissions standard or control requirement
Boilers—Coal, blast furnace gas, and coke oven gas	0.20 lb/mmBtu.
Boilers—Residual oil	0.20 lb/mmBtu.
Boilers—Distillate oil	0.12 lb/mmBtu.
Boilers—Natural gas	0.08 lb/mmBtu.

(d) *Compliance and Monitoring Requirements*—(1) *Compliance Requirements* (i) Each affected unit identified in Table 1 to paragraph (c) of this section must design, install, maintain, and continuously operate NO_X control devices as necessary to achieve emissions limits set forth in Table 1 to paragraph (c) of this section in a manner consistent with good air pollution control practices as described in 40 CFR 63.6(e).

(A) If you are the owner or operator of an affected unit not identified in paragraph (d)(1)(i)(B) of this section, you must submit to EPA a work plan for each affected unit within 180 days of the effective date of this rule identifying how each affected unit will comply with the emissions limits set forth in Table 1 to paragraph (c) of this section. Each work plan must include identification of the control device selected and the phased construction timeframe by which you will design, install, and consistently operate the device.

(B) For each taconite production kiln affected by this rule, you must install, maintain, and continuously operate low-NO_X burners to reduce existing average NO_X emissions from the facility by 40% during all periods of kiln operation.

(*1*) If you have already installed low-NO_X burners as required by the 2013 or 2016 Minnesota Regional Haze Federal Implementation Plans,[352] then you must submit a report to EPA within 180 days of the effective date of this rule demonstrating that the low-NO_X burner is designed to achieve 40% reduction of kiln NO_X emissions.

(*2*) If you have not yet installed low-NO_X burners as required by the 2013 or 2016 Minnesota Regional Haze Federal Implementation Plans, then you must submit a work plan identifying the low-NO_X burner selected and the phased construction timeframe by which you will design, install, and consistently operate the burner. Each work plan shall include performance test results obtained within five years of the effective date of this rule to be used as baseline emission testing data providing the basis for required emission reductions.

(2) *Monitoring Requirements* (i) For each unit identified in Table 1 to paragraph (c) of this section of this rule, you must install, operate, and maintain a NO_X continuous emission monitoring system (CEMS) to monitor compliance with the emissions limits set forth in Table 1 to paragraph (c) of this section. Each CEMS shall be installed and operated in accordance with requirements set forth at 40 CFR part 60, appendix B.

(ii) You must conduct a performance evaluation of each CEMS according to the requirements in 40 CFR 63.8 and according to 40 CFR part 60, appendix B.

(iii) You must notify EPA in writing of your intention to conduct a performance test at least 60 calendar days before the performance test is initially scheduled to begin in accordance with 40 CFR 63.7 (b).

(iv) As specified in 40 CFR 63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, each representing a different 15-minute period within the same hour, to have a valid hour of data.

(v) All CEMS data must be reduced as specified in 40 CFR 63.8(g)(2) and recorded as NO_X in parts per million by volume, dry basis (ppmvd).

(vi) Proper maintenance. You must maintain the CEMS equipment at all times that the unit is operating, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

(vii) You must conduct all monitoring in continuous operation at all times that the unit is operating, except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration drift checks and required zero and high-level adjustments). Quality assurance or control activities must be performed according to procedure 1 of 40 CFR part 60, appendix F.

(viii) Data recorded during monitoring malfunctions, associated repairs, out-of-control periods, and required quality assurance or control activities should not be used for purposes of calculating data averages. You must use all of the data collected from all other periods in assessing compliance. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring equipment to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. Any period for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(e) *Recordkeeping requirements* (1) You shall maintain records of the following information for each day the affected unit operates:

(i) Calendar date;

(ii) The average hourly NO_X emission rates measured or predicted;

(iii) The 30-day average NO_X emission rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO_X emission rates for the preceding 30 steam generating unit operating days;

(iv) Identification of the affected unit operating days when the calculated 30-day average NO_X emission rates are in excess of the applicable NO_X emission limit in Table 1 to paragraph (c) of this section with the reasons for such excess emissions as well as a description of corrective actions taken;

(v) Identification of the affected unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(vi) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(viii) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(ix) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3 in appendix B of 40 CFR part 60; and

(x) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F.

[352] *https://archive.epa.gov/reg5oair/taconite/web/html/index.html.*

(2) Any records required to be maintained by this section that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the EPA as part of an on-site compliance evaluation.

(f) *Reporting requirements* (1) Within 180 days of the effective date of this rule, you shall submit a work plan in accordance with requirements set forth in paragraph (d)(1)(i)(A) of this section, including identification of the control device selected and the phased construction timeframe by which you will design, install, and consistently operate the device. For taconite kilns subject to paragraph (d)(1)(i)(B)(2) of this section each work plan shall include performance test results obtained within five years of the effective date of this rule to be used as baseline emission testing data providing the basis for required emission reductions.

(2) By no later than March 30, 2026, each owner/operator of an affected unit shall submit a final report certifying installation of each selected control device has completed. Each such report shall contain dates of final construction and relevant performance testing, where applicable, demonstrating compliance with limits set forth in Table 1 to paragraph (c) of this section.

(3) Within 60 days after the date of completing each performance test required by this section, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in paragraphs (c)(3)(i) through (iii) of this section:

(i) *Data collected using test methods supported by the EPA's ERT as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.* Submit the results of the performance test to the EPA via the CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website.

(ii) *Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.* The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(iii) *CBI. Do not use CEDRI to submit information you claim as CBI.* Anything submitted using CEDRI cannot later be claimed CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraph (f)(1)(i) or (ii) of this section, you must submit a complete file, including information claimed to be CBI, to the EPA. The file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in paragraphs (f)(1)(i) and (ii). All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(4) You are required to submit excess emission reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under paragraph (c)(3)(iii) of this section, that exceeds the applicable emission limit in paragraph (c) of this section. Excess emission reports must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section.

(5) If you own or operate an affected unit subject to the continuous monitoring requirements for NO_X under paragraph (d) of this section, you shall submit reports containing the information recorded under paragraph (d) as described in paragraph (e)(6) of this section. Compliance reports for continuous monitoring must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section.

(6) If you own or operate an affected unit, you must submit electronic quarterly reports no later than 30 days after the end of the calendar quarter. The reports shall be accompanied by a certification from the owner or operator indicating whether the affected unit was in compliance with the applicable emission limits and minimum data requirements of this section during the reporting period. These quarterly reports must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section.

(7) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (f)(7)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(8) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that

reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (f)(8)(i) through (v) of this section.

(i) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(iv) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

§ 52.44 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Glass and Glass Product Manufacturing Industry?

(a) *Definitions.* All terms not defined herein shall have the meaning given them in the Act and in subpart A of part 60.

Affected units means a glass manufacturing furnace meeting the applicability criteria of this section.

All-electric melter means a glass melting furnace in which all the heat required for melting is provided by electric current from electrodes submerged in the molten glass, although some fossil fuel may be charged to the furnace as raw material only.

Borosilicate recipe means glass product composition of the following approximate ranges of weight proportions: 60 to 80 percent silicon dioxide, 4 to 10 percent total R_2O (*e.g.,* Na_2O and K_2O), 5 to 35 percent boric oxides, and 0 to 13 percent other oxides.

Container glass means glass made of soda-lime recipe, clear or colored, which is pressed and/or blown into bottles, jars, ampoules, and other products listed in Standard Industrial Classification 3221 (SIC 3221).

Experimental furnace means a glass melting furnace with the sole purpose of operating to evaluate glass melting processes, technologies, or glass products. An experimental furnace does not produce glass that is sold (except for further research and development purposes) or that is used as a raw material for nonexperimental furnaces.

Flat glass means glass made of soda-lime recipe and produced into continuous flat sheets and other products listed in SIC 3211.

Glass melting furnace means a unit comprising a refractory vessel in which raw materials are charged, melted at high temperature, refined, and conditioned to produce molten glass. The unit includes foundations, superstructure and retaining walls, raw material charger systems, heat exchangers, melter cooling system, exhaust system, refractory brick work, fuel supply and electrical boosting equipment, integral control systems and instrumentation, and appendages for conditioning and distributing molten glass to forming apparatuses. The forming apparatuses, including the float bath used in flat glass manufacturing and flow channels in wool fiberglass and textile fiberglass manufacturing, are not considered part of the glass melting furnace.

Glass produced means the weight of the glass pulled from the glass melting furnace.

Hand glass melting furnace means a glass melting furnace where the molten glass is removed from the furnace by a glassworker using a blowpipe or a pontil.

Lead recipe means glass product composition of the following ranges of weight proportions: 50 to 60 percent silicon dioxide, 18 to 35 percent lead oxides, 5 to 20 percent total R_2O (*e.g.,* Na_2O and K_2O), 0 to 8 percent total R_2O_3 (*e.g.,* Al_2O_3), 0 to 15 percent total RO (*e.g.,* CaO, MgO), other than lead oxide, and 5 to 10 percent other oxides.

Pressed and blown glass means glass which is pressed, blown, or both, including textile fiberglass, noncontinuous flat glass, noncontainer glass, and other products listed in SIC 3229. It is separated into: Glass of borosilicate recipe, Glass of soda-lime and lead recipes, and Glass of opal, fluoride, and other recipes.

Raw material means minerals, such as silica sand, limestone, and dolomite; inorganic chemical compounds, such as soda ash (sodium carbonate), salt cake (sodium sulfate), and potash (potassium carbonate); metal oxides and other metal-based compounds, such as lead oxide, chromium oxide, and sodium antimonate; metal ores, such as chromite and pyrolusite; and other substances that are intentionally added to a glass manufacturing batch and melted in a glass melting furnace to produce glass. Metals that are naturally-occurring trace constituents or contaminants of other substances are not considered to be raw materials.

Rebricking means cold replacement of damaged or worn refractory parts of the glass melting furnace. Rebricking includes replacement of the refractories comprising the bottom, sidewalls, or roof of the melting vessel; replacement of refractory work in the heat exchanger; replacement of refractory portions of the glass conditioning and distribution system.

Soda-lime recipe means glass product composition of the following ranges of weight proportions: 60 to 75 percent silicon dioxide, 10 to 17 percent total R_2O (*e.g.,* Na_2O and K_2O), 8 to 20 percent total RO but not to include any PbO (*e.g.,* CaO, and MgO), 0 to 8 percent total R_2O_3 (*e.g.,* Al_2O_3), and 1 to 5 percent other oxides.

Textile fiberglass means fibrous glass in the form of continuous strands having uniform thickness.

Wool fiberglass means fibrous glass of random texture, including fiber glass insulation, and other products listed in SIC 3296.

(b) *Applicability* You are subject to the requirements under this section if you own or operate a new or existing glass manufacturing furnace that directly emits or has the potential to emit 100 tons per year or more of NO_X and is located within any of the States listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such State(s).

(c) *Emissions limitations* If you own or operate an affected unit you are subject to the NO_X emissions limits in the following table beginning with the 2026 ozone season and in each ozone season thereafter:

TABLE 1 TO PARAGRAPH (c)

Furnace type	Proposed NO_X emissions limit (lb/ton of glass produced)
Container Glass Manufacturing Furnace	4.0
Pressed/Blown Glass Manufacturing Furnace or Fiberglass Manufacturing Furnace	4.0
Flat Glass Manufacturing Furnace	9.2

(d) *Testing and Monitoring Requirements* If you own or operate an affected unit you must conduct performance tests, on a semiannual basis, in accordance with the applicable reference test methods of 40 CFR part 60, Appendix A, any alternative test method approved by EPA as of April 6, 2022 under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii), or 65.158(a)(2) and available at EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by EPA through notice-and-comment rulemaking. Direct measurement or material balance using good engineering practice shall be used to determine the amount of glass pulled during the performance test. The rate of glass produced is defined as the weight of glass pulled from the affected facility during the performance test divided by the number of hours taken to perform the performance test.

(1) Owners or operators of affected units must calculate and record the 30-operating day rolling emission rate of NO_X as the total of all hourly emissions data for a glass manufacturing furnace in the preceding 30 days, divided by the total tons of glass produced in that furnace during the same 30-operating day period. If a continuous emission monitoring system has not been installed on the affected unit, the owner or operator shall conduct the following steps:

(A) *Step 1:* determine the average pounds of NO_X emitted per hour by averaging three one-hour tests,

(B) *Step 2:* determine the average tons of glass removed per hour during the same time period as the three one-hour tests in step 1,

(C) *Step 3:* divide the average pounds of NO_X emitted per hour determined in step 1 by the average tons of glass removed per hour determined in step 2,

(D) *Step 4:* compare the quotient to the emission limits specified at § 52.44(c)(1).

(2) If a continuous emission monitoring system has been installed on the affected unit, on a daily basis the owner or operator shall conduct the following steps:

(A) *Step 1:* determine the average pounds of NO_X emitted per day,

(B) *Step 2:* determine the tons of glass removed per day,

(C) *Step 3:* divide the average pounds of NO_X emitted per day determined in step (1) by the tons of glass removed per day determined in step (2). The quotient is pounds of NO_X emitted per ton of glass removed; and

(D) *Step 4:* compare the quotient to the emission limit specified at § 52.44(c)(1).

(e) *Recordkeeping requirements* (1) If you own or operate an affected unit, you must retain records of the calculations and measurements as required in paragraph (e) of this section for 5-year period specified in 52.40(b)(3). You must record the results of each inspection and maintenance proposed rule in a logbook (written or electronic format). You shall keep the logbook onsite and make the logbook available to the permitting authority upon request, consistent with the requirements of 40 CFR part 63, subpart SSSSSS, § 63.11457(c).

(2) Any records required to be maintained by this section that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the EPA as part of an on-site compliance evaluation.

(f) *Reporting requirements* (1) Within 60 days after the date of completing each performance test required by this section, you must submit the results of the performance test following the procedures specified in paragraphs (e)(1)(i) through (iii) of this section:

(i) *Data collected using test methods supported by the EPA's ERT as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.* Submit the results of the performance test to the EPA via the CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website.

(ii) *Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.* The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(iii) *CBI. Do not use CEDRI to submit information you claim as CBI.* Anything submitted using CEDRI cannot later be claimed CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraph (f)(1)(i) or (ii) of this section, you must submit a complete file, including information claimed to be CBI, to the EPA. The file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in paragraphs (f)(1)(i) and (ii). All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(2) If you own or operate an affected unit, you shall submit a semi-annual report, at least every six months, in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section.

(3) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (f)(3)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(4) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (f)(4)(i) through (v) of this section.

(i) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(iv) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

§ 52.45 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills Industries?

(a) *Definitions.* All terms not defined herein shall have the meaning given them in the Act and in subpart A of 40 CFR part 60.

Affected unit means an industrial boiler meeting the applicability criteria of this section.

(b) *Applicability.* (1) The requirements of this section apply to each new or existing boiler with a design capacity of 100 mmBtu/hr or greater fueled by coal, residual oil, distillate oil, or natural gas, located at sources that are within the Basic Chemical Manufacturing industry (NAICS code 3251xx), the Petroleum and Coal Products Manufacturing industry (NAICS code 3241xx), and the Pulp, Paper, and Paperboard industry (NAICS code 3221xx), and which is located within any of the States listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such State(s).

(c) *Emission limitations.* Beginning with the 2026 ozone season and in each ozone season thereafter, the following emission limits apply, based on a 30-day averaging time:

(1) Coal-fired industrial boilers: 0.20 lbs NO_X/mmBtu;

(2) Residual oil-fired industrial boilers: 0.15 lbs NO_X/mmBtu;

(3) Distillate oil-fired industrial boilers: 0.12 lbs NO_X/mmBtu; and

(4) Natural gas-fired industrial boilers: 0.08 lbs NO_X/mmBtu.

(d) *Initial compliance testing.* (1) To determine compliance with the emission limits for NO_X identified in paragraph (c) of this section, you shall conduct an initial compliance test as described in 40 CFR § 60.8 using the continuous system for monitoring NO_X specified by EPA Test Method 7E—Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure), as described at 40 CFR part 60, Appendix A–4. In lieu of the timing of the compliance test described in 40 CFR 60.8(a), the test shall be conducted within 90 days from the installation of the pollution control equipment used to comply with the NO_X emission limits in paragraph (c) of this section.

(2) For the initial compliance test, NO_X emissions from the affected unit shall be monitored for 30 successive operating days and the 30-day average emission rate will be used to determine compliance with the NO_X emission limits in paragraph (c) of this section. The 30-day average emission rate is calculated as the average of all hourly emission data recorded by the monitoring system during the 30-day test period.

(e) *Monitoring requirements.* (1) The NO_X emission limits in paragraph (c) of this section shall apply at all times.

(2) You shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO_X emissions and either oxygen (O_2) or carbon dioxide (CO_2), unless the Administrator has approved a request from the you to use an alternative monitoring technique under paragraph (e)(8) of this section. If you have previously installed a NO_X emission rate CEMS to meet the requirements of 40 CFR part 75 and continue to meet the ongoing requirements of 40 CFR part 75, that CEMS may be used to meet the monitoring requirements of this section.

(3) The CEMS required under paragraph (e)(2) of this section shall be operated and data recorded during all periods of operation of the affected unit except for CEMS breakdowns and repairs. Data shall be recorded during calibration checks and zero and span adjustments.

(4) The 1-hour average NO_X emission rates measured by the CEMS required by paragraph (e)(2) of this section shall be expressed in terms of lbs/mmBtu heat input and shall be used to calculate the average emission rates under 40 CFR 52.45(c).

(5) Following the date on which the initial compliance test is completed, you shall determine compliance with the applicable NO_X emission limit in paragraph (c) of this section on a continuous basis using a 30-day rolling

average emission rate unless the affected unit monitors emissions by means of an alternative monitoring procedure approved pursuant to paragraph (e)(8) of this section. A new 30-day rolling average emission rate is calculated for each operating day as the average of all the hourly NO_X emission data for the preceding 30 operating days.

(6) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems. Additionally, the span value for units combusting coal shall be 1,000 ppm NO_X, and for units combusting oil or gas the span value shall be 500 ppm NO_X. As an alternative to meeting the span value requirements stated above, you may elect to use the NO_X span values determined according to section 2.1.2 in appendix A to 40 CFR part 75.

(7) When NO_X emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of 40 CFR part 60, Method 7A of 40 CFR part 60, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each affected unit operating day, in at least 22 out of 30 successive operating days.

(8) Installation of a CEMS for NO_X may be delayed until after the initial performance test has been conducted. If you demonstrate during the performance test that emissions of NO_X are less than 70 percent of the applicable emission limit in paragraph (c) of this section, a CEMS for measuring NO_X emissions is not required. If you demonstrate its boiler emits less than 70 percent of the applicable emission limit chooses to not install a CEMS, you must submit a written request to the Administrator that documents the results of the initial performance test and includes an alternative monitoring procedure that will be used to track compliance with the applicable NO_X emission limit(s) in paragraph (c) of this section. The Administrator will consider the request and, following public notice and comment, may approve the alternative monitoring procedure with or without revision, or disapprove the request. Upon receipt of a disapproved request, you will have one year to install a CEMS in accordance with the provisions for CEMS described in paragraph (e) of this section.

(f) *Recordkeeping requirements* (1) You shall record and maintain records of the amounts of each fuel combusted during each calendar month.

(2) You shall maintain records of the following information for each day the affected unit operates:

(i) Calendar date;

(ii) The average hourly NO_X emission rates (expressed as lbs NO_2/mmBtu heat input) measured or predicted;

(iii) The 30-day average NO_X emission rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO_X emission rates for the preceding 30 steam generating unit operating days;

(iv) Identification of the affected unit operating days when the calculated 30-day average NO_X emission rates are in excess of the applicable NO_X emission limit in paragraph (c) of this section with the reasons for such excess emissions as well as a description of corrective actions taken;

(v) Identification of the affected unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(vi) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(vii) Identification of ''F'' factor used for calculations, method of determination, and type of fuel combusted;

(viii) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(ix) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3 in appendix B of 40 CFR part 60; and

(x) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F.

(3) Any records required to be maintained by this section that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the EPA as part of an on-site compliance evaluation.

(g) *Reporting requirements.* (1) Within 60 days after the date of completing each performance test required by this section, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in paragraphs (g)(i) through (iii) of this section:

(i) *Data collected using test methods supported by the EPA's ERT as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.* Submit the results of the performance test to the EPA via the CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website.

(ii) *Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.* The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(iii) *CBI. Do not use CEDRI to submit information you claim as CBI.* Anything submitted using CEDRI cannot later be claimed CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraph (g)(1)(i) or (ii) of this section, you must submit a complete file, including information claimed to be CBI, to the EPA. The file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in paragraphs (g)(1)(i) and (ii) of this section. All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(2) You are required to submit excess emission reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under paragraph (g)(3)(iii) of this section, that exceeds the applicable emission limit in paragraph (c) of this section. Excess emission reports must be

submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section.

(3) If you own or operate an affected unit subject to the continuous monitoring requirements for NO_X under paragraph (e) of this section, you shall submit reports containing the information recorded under paragraph (e) of this section as described in paragraph (g)(2) of this section. Compliance reports for continuous monitoring must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section.

(4) If you own or operate an affected unit, you must submit electronic quarterly reports no later than 30 days after the end of the calendar quarter. The reports shall be accompanied by a certification from the owner or operator indicating whether the affected unit was in compliance with the applicable emission limits and minimum data requirements of this section during the reporting period. These quarterly reports must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section.

(5) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (g)(5)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(6) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (g)(6)(i) through (v) of this section.

(i) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(iv) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

Subpart B—Alabama

■ 5. Amend § 52.54 by revising paragraphs (b)(2) and (3) and adding paragraphs (b)(4) and (5) to read as follows:

§ 52.54 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b) * * *

(2) The owner and operator of each source and each unit located in the State of Alabama and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 through 2022. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(ii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's SIP.

(3) The owner and operator of each source and each unit located in the State of Alabama and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the

promulgation of an approval by the Administrator of a revision to Alabama's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's SIP.

(4) Notwithstanding the provisions of paragraphs (b)(2) and (3) of this section, if, at the time of the approval of Alabama's SIP revision described in paragraph (b)(2) or (3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances or CSAPR NO_X Ozone Season Group 3 allowances under subpart EEEEE or GGGGG, respectively, of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (b)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

Subpart E—Arkansas

■ 6. Amend § 52.184 by:

■ a. Redesignating paragraphs (a) through (c) as paragraphs (a)(1) through (3);

■ b. In newly redesignated paragraph (a)(2), removing "2017 and each subsequent year." and adding in its place "2017 through 2022.", and removing the second sentence;

■ c. Revising newly redesignated paragraph (a)(3); and

■ d. Adding paragraphs (a)(4) and (5) and (b).

The revision and additions read as follows:

§ 52.184 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) * * *

(3) The owner and operator of each source and each unit located in the State of Arkansas and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Arkansas' State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii), except to the extent the Administrator's approval is partial or conditional.

(4) Notwithstanding the provisions of paragraph (a)(3) of this section, if, at the time of the approval of Arkansas' SIP revision described in paragraph (a)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (a)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State for control periods after 2022) shall continue to apply.

(b) The owner and operator of each source located in the State of Arkansas and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart F—California

■ 7. Add § 52.284 to read as follows:

§ 52.284 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

The owner and operator of each source located in the State of California and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart I—Delaware

■ 8. Amend § 52.440 by adding paragraph (d) to read as follows:

§ 52.440 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d)(1) The owner and operator of each source and each unit located in the State of Delaware and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Delaware's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (d)(1) of this section, if, at the time of the approval of Delaware's SIP

revision described in paragraph (d)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart O—Illinois

■ 9. Amend § 52.731 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.731 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Illinois and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart P—Indiana

■ 10. Amend § 52.789 by:
■ a. In paragraph (b)(2), removing ''(b)(2)(iv), except'' and adding in its place ''(b)(2)(ii), except'';
■ b. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ c. Adding paragraph (c).

The addition reads as follows:

§ 52.789 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Indiana and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart S—Kentucky

■ 11. Amend § 52.940 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.940 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Kentucky and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart T—Louisiana

■ 12. Amend § 52.984 by:
■ a. In paragraph (d)(3), revising the second and third sentences;
■ b. Revising paragraph (d)(4);
■ c. In paragraph (d)(5), adding ''and Indian country within the borders of the State'' after ''in the State''; and
■ d. Adding paragraph (e).

The revision and addition read as follows:

§ 52.984 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d) * * *

(3) * * * The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Louisiana's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and(b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Louisiana's SIP.

(4) Notwithstanding the provisions of paragraph (d)(3) of this section, if, at the time of the approval of Louisiana's SIP revision described in paragraph (d)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

* * * * *

(e) The owner and operator of each source located in the State of Louisiana and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart V—Maryland

■ 13. Amend § 52.1084 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.1084 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Maryland and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart X—Michigan

■ 14. Amend § 52.1186 by:
■ a. In paragraph (e)(3), revising the second and third sentences;
■ b. Revising paragraph (e)(4);
■ c. In paragraph (e)(5), adding ''and Indian country within the borders of the State'' after ''in the State''; and
■ d. Adding paragraph (f).

The revision and addition read as follows:

§ 52.1186 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(e) * * *

(3) * * * The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the

Administrator of a revision to Michigan's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and(b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Michigan's SIP.

(4) Notwithstanding the provisions of paragraph (e)(3) of this section, if, at the time of the approval of Michigan's SIP revision described in paragraph (e)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

* * * * *

(f) The owner and operator of each source located in the State of Michigan and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart Y—Minnesota

■ 15. Amend § 52.1240 by adding paragraphs (d) and (e) to read as follows:

§ 52.1240 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d)(1) The owner and operator of each source and each unit located in the State of Minnesota and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Minnesota's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Minnesota's SIP.

(2) Notwithstanding the provisions of paragraph (d)(1) of this section, if, at the time of the approval of Minnesota's SIP revision described in paragraph (d)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(e) The owner and operator of each source located in the State of Minnesota and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart Z—Mississippi

■ 16. Amend § 52.1284 by:

■ a. Redesignating paragraphs (a) through (c) as paragraphs (a)(1) through (3);

■ b. In newly redesignated paragraph (a)(2), removing "2017 and each subsequent year." and adding in its place "2017 through 2022.", and removing the second and third sentences;

■ c. Revising newly redesignated paragraph (a)(3); and

■ d. Adding paragraphs (a)(4) and (5) and (b).

The revision and additions read as follows:

§ 52.1284 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) * * *

(3) The owner and operator of each source and each unit located in the State of Mississippi and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Mississippi's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Mississippi's SIP.

(4) Notwithstanding the provisions of paragraph (a)(3) of this section, if, at the time of the approval of Mississippi's SIP revision described in paragraph (a)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (a)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of

CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

(b) The owner and operator of each source located in the State of Mississippi and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart AA—Missouri

■ 17. Amend § 52.1326 by revising paragraph (b)(2) and (3) and adding paragraphs (b)(4) and (5) and (c) to read as follows:

§ 52.1326 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b) * * *

(2) The owner and operator of each source and each unit located in the State of Missouri and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 through 2022. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Missouri's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(ii), except to the extent the Administrator's approval is partial or conditional.

(3) The owner and operator of each source and each unit located in the State of Missouri and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Missouri's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii), except to the extent the Administrator's approval is partial or conditional.

(4) Notwithstanding the provisions of paragraphs (b)(2) and (3) of this section, if, at the time of the approval of Missouri's SIP revision described in paragraph (b)(2) or (3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances or CSAPR NO_X Ozone Season Group 3 allowances under subpart EEEEE or GGGGG, respectively, of part 97 of this chapter to units in the State for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (b)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State for control periods after 2022) shall continue to apply.

(c) The owner and operator of each source located in the State of Missouri and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart DD—Nevada

■ 18. Add § 52.1492 to read as follows:

§ 52.1492 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Nevada and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Nevada's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Nevada's SIP.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Nevada's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b) The owner and operator of each source located in the State of Nevada and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart FF—New Jersey

■ 19. Amend § 52.1584 by:

■ a. In paragraph (e)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and

■ b. Adding paragraph (f).

The addition reads as follows:

§ 52.1584 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(f) The owner and operator of each source located in the State of New Jersey and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart HH—New York

■ 20. Amend § 52.1684 by:

■ a. In paragraph (b)(3), revising the second and third sentences;

■ b. Revising paragraph (b)(4);

■ c. In paragraph (b)(5), adding ''and Indian country within the borders of the State'' after ''in the State''; and

■ d. Adding paragraph (c).

The revision and addition read as follows:

§ 52.1684 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b) * * *

(3) * * * The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to New York's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and(b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to New York's SIP.

(4) Notwithstanding the provisions of paragraph (b)(3) of this section, if, at the time of the approval of New York's SIP revision described in paragraph (b)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

* * * * *

(c) The owner and operator of each source located in the State of New York and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart KK—Ohio

■ 21. Amend § 52.1882 by:

■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and

■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.1882 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Ohio and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart LL—Oklahoma

■ 22. Amend § 52.1930 by:

■ a. Redesignating paragraphs (a) through (c) as paragraphs (a)(1) through (3);

■ b. In newly redesignated paragraph (a)(2), removing ''2017 and each subsequent year.'' and adding in its place ''2017 through 2022.'', and removing the second and third sentences;

■ c. Revising newly redesignated paragraph (a)(3); and

■ c. Adding paragraphs (a)(4) and (5) and (b).

The revision and additions read as follows:

§ 52.1930 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) * * *

(3) The owner and operator of each source and each unit located in the State of Oklahoma and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Oklahoma's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Oklahoma's SIP.

(4) Notwithstanding the provisions of paragraph (a)(3) of this section, if, at the time of the approval of Oklahoma's SIP revision described in paragraph (a)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (a)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts

of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

(b) The owner and operator of each source located in the State of Oklahoma and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart NN—Pennsylvania

■ 23. Amend § 52.2040 by:

■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and

■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.2040 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Pennsylvania and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart RR—Tennessee

■ 24. Amend § 52.2240 by:

■ a. In paragraph (e)(2), removing ''2017 and each subsequent year.'' and adding in its place ''2017 through 2022.'', and removing the second sentence;

■ b. Revising paragraph (e)(3); and

■ c. Adding paragraphs (e)(4) and (5).

The revision and additions read as follows:

§ 52.2240 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(e) * * *

(3) The owner and operator of each source and each unit located in the State of Tennessee and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Tennessee's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii), except to the extent the Administrator's approval is partial or conditional.

(4) Notwithstanding the provisions of paragraph (e)(3) of this section, if, at the time of the approval of Tennessee's SIP revision described in paragraph (e)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (e)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State for control periods after 2022) shall continue to apply.

Subpart SS—Texas

■ 25. Amend § 52.2283 by:

■ a. In paragraph (d)(2), removing ''2017 and each subsequent year.'' and adding in its place ''2017 through 2022.'', and removing the second and third sentences;

■ b. Revising paragraph (d)(3); and

■ c. Adding paragraphs (d)(4) and (5) and (e).

The revision and additions read as follows:

§ 52.2283 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d) * * *

(3) The owner and operator of each source and each unit located in the State of Texas and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Texas' State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Texas' SIP.

(4) Notwithstanding the provisions of paragraph (d)(3) of this section, if, at the time of the approval of Texas' SIP revision described in paragraph (d)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (d)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter

(concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

(e) The owner and operator of each source located in the State of Texas and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart TT—Utah

■ 26. Add § 52.2356 to read as follows:

§ 52.2356 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Utah and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Utah's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Utah's SIP.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Utah's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b) The owner and operator of each source located in the State of Utah and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart VV—Virginia

■ 27. Amend § 52.2440 by:

■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and

■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.2440 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Virginia and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart XX—West Virginia

■ 28. Amend § 52.2540 by:

■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and

■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.2540 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of West Virginia and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart YY—Wisconsin

■ 29. Amend § 52.2587 by:

■ a. In paragraph (e)(2), removing ''2017 and each subsequent year.'' and adding in its place ''2017 through 2022.'', and removing the second and third sentences;

■ b. Revising paragraph (e)(3); and

■ c. Adding paragraphs (e)(4) and (5) and (f).

The revision and additions read as follows:

§ 52.2587 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(e) * * *

(3) The owner and operator of each source and each unit located in the State of Wisconsin and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Wisconsin's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Wisconsin's SIP.

(4) Notwithstanding the provisions of paragraph (e)(3) of this section, if, at the time of the approval of Wisconsin's SIP revision described in paragraph (e)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart

GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (e)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

(f) The owner and operator of each source located in the State of Wisconsin and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart ZZ—Wyoming

■ 30. Add § 52.2638 to read as follows:

§ 52.2638 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Wyoming and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Wyoming State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Wyoming's SIP.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Wyoming's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b) The owner and operator of each source located in the State of Wyoming and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

PART 75—CONTINUOUS EMISSION MONITORING

■ 31. The authority citation for part 75 is revised to read as follows:

Authority: 42 U.S.C. 7401–7671q and 7651k note.

■ 32. Amend § 75.72 by:

■ a. In paragraph (c)(3), removing ''appendix B of this part.'' and adding in its place ''appendix B to this part.'';

■ b. In paragraph (e)(1)(ii), removing ''heat input from'' and adding in its place ''heat input rate to'';

■ c. In paragraph (e)(2), removing ''appendix D of this part'' and adding in its place ''appendix D to this part''; and

■ d. Adding paragraph (f).

The addition reads as follows:

§ 75.72 Determination of NO_X mass emissions for common stack and multiple stack configurations.

* * * * *

(f) *Procedures for apportioning hourly NO_X mass emission rate to the unit level.* If the owner or operator of a unit determining hourly NO_X mass emission rate at a common stack under this section is subject to a State or federal NO_X mass emissions reduction program under subpart GGGGG of part 97 of this chapter or under a state implementation plan approved pursuant to § 52.38(b)(12) of this chapter, then on and after January 1, 2024, the owner or operator shall apportion the hourly NO_X mass emissions rate at the common stack to each unit using the common stack based on the ratio of the hourly heat input rate for each such unit to the total hourly heat input rate for all such units, in conjunction with the appropriate unit and stack operating times, according to the procedures in section 8.5.3 of appendix F to this part.

* * * * *

■ 33. Amend § 75.73 by:

■ a. Revising paragraph (a)(3);

■ b. In paragraph (c)(1), removing ''No_X emissions'' and adding in its place ''NO_X emissions'';

■ c. Adding a paragraph heading to paragraph (c)(2);

■ d. Revising paragraphs (c)(3) and (f)(1) introductory text;

■ e. Removing and reserving paragraph (f)(1)(i)(B);

■ f. In paragraph (f)(1)(ii)(G), removing ''appendix D;'' and adding in its place ''appendix D to this part;'';

■ g. Adding paragraphs (f)(1)(ix) and (x);

■ h. Adding a paragraph heading to paragraph (f)(2); and

■ i. Revising paragraph (f)(4).

The revisions and addition reads as follows:

§ 75.73 Recordkeeping and reporting.

* * * * *

(a) * * *

(3) For each hour when the unit is operating, NO_X mass emission rate, calculated in accordance with section 8 of appendix F to this part.

* * * * *

(c) * * *

(2) *Monitoring plan updates.* * * *

(3) *Contents of the monitoring plan.* Each monitoring plan shall contain the information in § 75.53(g)(1) in electronic format and the information in § 75.53(g)(2) in hardcopy format. In addition, to the extent applicable, each monitoring plan shall contain the information in § 75.53(h)(1)(i) and (h)(2)(i) in electronic format and the information in § 75.53(h)(1)(ii) and (h)(2)(ii) in hardcopy format. For units using the low mass emissions excepted methodology under § 75.19, the monitoring plan shall include the additional information in § 75.53(h)(4)(i) and (h)(4)(ii). The monitoring plan also

shall include a seasonal controls indicator and an ozone season fuel-switching flag.

(f) * * *

(1) *Electronic submission.* The designated representative for an affected unit shall electronically report the data and information in this paragraph (f)(1) and in paragraphs (f)(2) and (3) of this section to the Administrator quarterly, unless the unit has been placed in long-term cold storage (as defined in § 72.2 of this chapter). Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Each electronic report shall include the information provided in paragraphs (f)(1)(i) through (x) of this section and shall also include the date of report generation. A unit placed into long-term cold storage is exempted from submitting quarterly reports beginning with the calendar quarter following the quarter in which the unit is placed into long-term cold storage, provided that the owner or operator shall submit quarterly reports for the unit beginning with the data from the quarter in which the unit recommences operation (where the initial quarterly report contains hourly data beginning with the first hour of recommenced operation of the unit).

* * * * *

(ix) On and after on January 1, 2024, for a unit subject to subpart GGGGG of part 97 of this chapter or a state implementation plan approved under § 52.38(b)(12) of this chapter and determining NO_X mass emission rate at a common stack, apportioned hourly NO_X mass emission rate for the unit, lb/hr.

(x) On and after January 1, 2024, for a unit subject to a backstop daily NO_X emission rate under subpart GGGGG of part 97 of this chapter or under a state implementation plan approved under § 52.38(b)(12) of this chapter:

(A) Daily NO_X emissions (lbs) for each day of the reporting period;

(B) Daily heat input (mmBtu) for each day of the reporting period;

(C) Daily average NO_X emission rate (lb/mmBtu, rounded to the nearest thousandth) for each day of the reporting period;

(D) Daily NO_X emissions (lbs) exceeding the applicable backstop daily NO_X emission rate for each day of the reporting period; and

(E) Cumulative NO_X emissions (tons, rounded to the nearest tenth) exceeding the applicable backstop daily NO_X emission rate during the ozone season.

(2) *Verification of identification codes and formulas.* * * *

* * * * *

(4) *Electronic format, method of submission, and explanatory information.* The designated representative shall comply with all of the quarterly reporting requirements in § 75.64(d), (f), and (g).

■ 34. Revise § 75.75 to read as follows:

§ 75.75 Additional ozone season calculation procedures.

(a) The owner or operator of a unit that is required to calculate daily or ozone season heat input shall do so by summing the unit's hourly heat input determined according to the procedures in this part for all hours in which the unit operated during the day or ozone season.

(b) The owner or operator of a unit that is required to determine daily or ozone season NO_X emission rate (in lbs/mmBtu) shall do so by dividing daily or ozone season NO_X mass emissions (in lbs) determined in accordance with this subpart, by daily or ozone season heat input determined in accordance with paragraph (a) of this section.

■ 35. Amend appendix F to part 75 by:

■ a. Adding section 5.3.3;

■ b. In section 8.1.2, revising the introductory text preceding Equation F–25;

■ c. In section 8.4, revising the introductory text, paragraph (a) introductory text (preceding Equation F–27), and paragraph (b) introductory text (preceding Equation F–27a), and adding paragraph (c);

■ d. In section 8.5.2, removing ''the hourly NO_X mass emissions at each unit'' and adding in its place ''hourly NO_X mass emissions at the common stack.''; and

■ e. Adding section 8.5.3.

The additions and revisions read as follows

Appendix F to Part 75—Conversion Procedures

* * * * *

5.3.3 Calculate total daily heat input for a unit using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_d = \sum_{h=1}^{24} HI_h t_h$$

(Eq. F-18c)

Where:

HI_d = Total heat input for a unit for the day, mmBtu.

HI_h = Heat input rate for the unit for hour ''h'' from Equation F–15, F–16, F–17, F–18, F–21a, or F–21b, mmBtu/hr.

t_h = Unit operating time, fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

h = Designation of a particular hour.

* * * * *

8.1.2 If NO_X emission rate is measured at a common stack and heat input rate is measured at the unit level, calculate the hourly heat input rate at the common stack according to the following formula:

* * * * *

8.4 Use the following equations to calculate daily, quarterly, cumulative ozone season, and cumulative year-to-date NO_X mass emissions:

(a) When hourly NO_X mass emissions are reported in lb., use Eq. F–27 to calculate quarterly, cumulative ozone season, and cumulative year-to-date NO_X mass emissions in tons. * * *

(b) When hourly NO_X mass emission rate is reported in lb/hr, use Eq. F–27a to calculate quarterly, cumulative ozone season, and cumulative year-to-date NO_X mass emissions in tons. * * *

(c) To calculate daily NO_X mass emissions for a unit in pounds, use Eq. F–27b.

$$M_{(NOX)_d} = \sum_{h=1}^{24} E_{(NOX)_h}\, t_h$$

(Eq. F-27b)

Where:

$M_{(NOX)_d}$ = NO_X mass emissions for a unit for the day, pounds.

$E_{(NOX)_h}$ = NO_X mass emission rate for the unit for hour "h" from Equation F–24a, F–26a, F–26b, or F–28, lb/hr.

t_h = Unit operating time, fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

h = Designation of a particular hour.

* * * * *

8.5.3 Where applicable, the owner or operator of a unit that determines hourly NO_X mass emission rate at a common stack shall apportion hourly NO_X mass emissions rate to the units using the common stack based on the hourly heat input rate, using Equation F–28:

$$E_{(NOX)_i} = E_{(NOX)_{CS}} \left(\frac{t_{CS}}{t_i}\right)\left[\frac{HI_i t_i}{\sum_{i=1}^{n} HI_i t_i}\right]$$

(Eq. F-28)

Where:

$E_{(NOX)_i}$ = Apportioned NO_X mass emission rate for unit "i", lb/hr.

$E_{(NOX)_{CS}}$ = NO_X mass emission rate at the common stack, lb/hr.

HI_i = Heat input rate for unit "i", mmBtu/hr.

t_i = Operating time for unit "i", fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS} = Common stack operating time, fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Number of units using the common stack.

i = Designation of a particular unit.

PART 78—APPEAL PROCEDURES

■ 36. The authority citation for part 78 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 37. Amend § 78.1 by:

■ a. In paragraph (b)(17)(viii), adding "or (e)" after "§ 97.826(d)";

■ b. In paragraph (b)(17)(ix), adding "or (e)" after "§ 97.811(d)"; and

■ c. Revising paragraph (b)(19).

The revision reads as follows:

§ 78.1 Purpose and scope.

* * * * *

(b) * * *

(19) Under subpart GGGGG of part 97 of this chapter,

(i) The decision on the calculation of a state CSAPR NO_X Ozone Season Group 3 trading budget under § 97.1010(a)(3) of this chapter.

(ii) The decision on the allocation of CSAPR NO_X Ozone Season Group 3 allowances under § 97.1011 or § 97.1012 of this chapter.

(iii) The decision on the transfer of CSAPR NO_X Ozone Season Group 3 allowances under § 97.1023 of this chapter.

(iv) The decision on the deduction of CSAPR NO_X Ozone Season Group 3 allowances under § 97.1024, § 97.1025, or § 97.1026(d) of this chapter.

(v) The correction of an error in an Allowance Management System account under § 97.1027 of this chapter.

(vi) The adjustment of information in a submission and the decision on the deduction and transfer of CSAPR NO_X Ozone Season Group 3 allowances based on the information as adjusted under § 97.1028 of this chapter.

(vii) The finalization of control period emissions data, including retroactive adjustment based on audit.

(viii) The approval or disapproval of a petition under § 97.1035 of this chapter.

* * * * *

PART 97—FEDERAL NO_X BUDGET TRADING PROGRAM, CAIR NO_X AND SO_2 TRADING PROGRAMS, CSAPR NO_X AND SO_2 TRADING PROGRAMS, AND TEXAS SO_2 TRADING PROGRAM

■ 38. The authority citation for part 97 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7426, 7491, 7601, and 7651, *et seq.*

Subpart AAAAA—CSAPR NO_X Annual Trading Program

§ 97.402 [Amended]

■ 39. Amend § 97.402 by:

■ a. In the definition of "CSAPR NO_X Ozone Season Group 1 Trading Program", removing "(b)(2)(i) and (ii), and" and adding in its place "(b)(2)(i), and";

■ b. In the definition of "CSAPR NO_X Ozone Season Group 2 Trading Program", removing "(b)(2)(iii) and (iv), and" and adding in its place "(b)(2)(ii), and"; and

■ c. In the definition of "CSAPR NO_X Ozone Season Group 3 Trading Program", removing "(b)(2)(v), and" and adding in its place "(b)(2)(iii), and";

§ 97.411 [Amended]

■ 40. Amend § 97.411 by:

■ a. In paragraphs (b)(1)(i)(A) and (B), removing "State, in accordance" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance"; and

■ b. In paragraphs (b)(2)(i)(A) and (B), removing "Indian country within the borders of a State, in accordance" and adding in its place "areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance".

§ 97.412 [Amended]

■ 41. Amend § 97.412 by:

■ a. In paragraph (a) introductory text, removing "State, the Administrator" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator";

■ b. In paragraphs (a)(3)(iii) and (a)(5), adding "and areas of Indian country within the borders of the State subject to the State's SIP authority" after "in the State";

■ c. In paragraph (a)(10), removing "State, is allocated" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';

■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator''; and

■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

§ 97.421 [Amended]

■ 42. In § 97.421, amend paragraph (f)(2) by removing ''2022'' and adding in its place ''2024'', and removing ''third'' before ''year after the year''.

§ 97.426 [Amended]

■ 43. In § 97.426, amend paragraph (c) by removing ''State (or Indian'' and adding in its place ''State (and Indian''.

Subpart BBBBB—CSAPR NO_X Ozone Season Group 1 Trading Program

§ 97.502 [Amended]

■ 44. Amend § 97.502 by:

■ a. In the definition of ''CSAPR NO_X Ozone Season Group 1 Trading Program'', removing ''(b)(2)(i) and (ii), and'' and adding in its place ''(b)(2)(i), and'';

■ b. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';

■ c. In the definition of ''CSAPR NO_X Ozone Season Group 3 allowance'', adding ''or (e)'' after ''§ 97.826(d)'', and adding ''or less'' after ''one ton'';

■ d. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and''; and

■ e. In the definition of ''State'', removing ''(b)(2)(i) and (ii), and'' and adding in its place ''(b)(2)(i), and''.

§ 97.511 [Amended]

■ 45. Amend § 97.511 by:

■ a. In paragraphs (b)(1)(i)(A) and (B), removing ''State, in accordance'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance''; and

■ b. In paragraphs (b)(2)(i)(A) and (B), removing ''Indian country within the borders of a State, in accordance'' and adding in its place ''areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance''.

§ 97.512 [Amended]

■ 46. Amend § 97.512 by:

■ a. In paragraph (a) introductory text, removing ''State, the Administrator'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator'';

■ b. In paragraphs (a)(3)(iii) and (a)(5), adding ''and areas of Indian country within the borders of the State subject to the State's SIP authority'' after ''in the State'';

■ c. In paragraph (a)(10), removing ''State, is allocated'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';

■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator''; and

■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

§ 97.521 [Amended]

■ 47. In § 97.521, amend paragraph (f)(2) by removing ''2022'' and adding in its place ''2024'', and removing ''third'' before ''year after the year''.

■ 48. Amend § 97.526 by:

■ a. In paragraph (c), removing ''State (or Indian'' and adding in its place ''State (and Indian'';

■ b. In paragraph (d)(1) introductory text, removing ''§ 52.38(b)(2)(i) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(i)(A) of this chapter (and'';

■ c. In paragraph (d)(1)(ii), removing ''except a State listed in § 52.38(b)(2)(i)'' and adding in its place ''listed in § 52.38(b)(2)(ii)'';

■ d. In paragraph (d)(1)(iv), removing ''§ 52.38(b)(2)(iii) or (iv) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(ii) of this chapter (and'';

■ e. Revising paragraph (d)(2)(i);

■ f. In paragraph (d)(2)(ii), removing ''§ 52.38(b)(2)(v) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(iii)(A) of this chapter (and'';

■ g. Adding paragraph (d)(2)(iii);

■ h. In paragraph (e)(1), removing ''chapter (or Indian'' and adding in its place ''chapter (and Indian'';

■ i. In paragraph (e)(2), removing ''§ 52.38(b)(2)(iv) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(iii)(A) of this chapter (and''; and

■ j. Adding paragraph (e)(3).

The revisions and additions read as follows:

§ 97.526 Banking and conversion.

* * * * *

(d) * * *

(2)(i) Except as provided in paragraphs (d)(2)(ii) and (iii) of this section, after the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section, upon any determination that would otherwise result in the initial recordation of a given number of CSAPR NO_X Ozone Season Group 1 allowances in the compliance account for a source in a State listed in § 52.38(b)(2)(ii) of this chapter (and Indian country within the borders of such a State), the Administrator will not record such CSAPR NO_X Ozone Season Group 1 allowances but instead will allocate and record in such account an amount of CSAPR NO_X Ozone Season Group 2 allowances for the control period in 2017 computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section.

* * * * *

(iii) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section and § 97.826(e)(1), upon any determination that would otherwise result in the initial recordation of a given number of CSAPR NO_X Ozone Season Group 1 allowances in the compliance account for a source in a State listed in § 52.38(b)(2)(iii)(B) of this chapter (and Indian country within the borders of such a State), the Administrator will not record such CSAPR NO_X Ozone Season Group 1 allowances but instead will allocate and record in such account an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section and further divided by the conversion factor determined under § 97.826(e)(1)(ii).

* * * * *

(e) * * *

(3) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section and § 97.826(e)(1), the owner or operator of a CSAPR NO_X Ozone Season Group 1

source in a State listed in § 52.38(b)(2)(iii)(B) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Group 1 allowances for the control period in 2015 or 2016 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 (or any later control period for which the allowance transfer deadline defined in § 97.1002 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section and further divided by the conversion factor determined under § 97.826(e)(1)(ii).

Subpart CCCCC—CSAPR SO_2 Group 1 Trading Program

§ 97.602 [Amended]

■ 49. Amend § 97.602 by:

■ a. In the definition of "CSAPR NO_X Ozone Season Group 1 Trading Program", removing "(b)(2)(i) and (ii), and" and adding in its place "(b)(2)(i), and";

■ b. In the definition of "CSAPR NO_X Ozone Season Group 2 Trading Program", removing "(b)(2)(iii) and (iv), and" and adding in its place "(b)(2)(ii), and";

■ c. In the definition of "CSAPR NO_X Ozone Season Group 3 Trading Program", removing "(b)(2)(v), and" and adding in its place "(b)(2)(iii), and";

§ 97.611 [Amended]

■ 50. Amend § 97.611 by:

■ a. In paragraphs (b)(1)(i)(A) and (B), removing "State, in accordance" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance"; and

■ b. In paragraphs (b)(2)(i)(A) and (B), removing "Indian country within the borders of a State, in accordance" and adding in its place "areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance".

§ 97.612 [Amended]

■ 51. Amend § 97.612 by:

■ a. In paragraph (a) introductory text, removing "State, the Administrator" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator";

■ b. In paragraphs (a)(3)(iii) and (a)(5), adding "and areas of Indian country within the borders of the State subject to the State's SIP authority" after "in the State";

■ c. In paragraph (a)(10), removing "State, is allocated" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated";

■ d. In paragraph (b) introductory text, removing "Indian country within the borders of each State, the Administrator" and adding in its place "areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator"; and

■ e. In paragraph (b)(5), removing "Indian country within the borders of the State" and adding in its place "areas of Indian country within the borders of the State not subject to the State's SIP authority".

§ 97.621 [Amended]

■ 52. In § 97.621, amend paragraph (f)(2) by removing "2022" and adding in its place "2024", and removing "third" before "year after the year".

§ 97.626 [Amended]

■ 53. In § 97.626, amend paragraph (c) by removing "State (or Indian" and adding in its place "State (and Indian".

Subpart DDDDD—CSAPR SO_2 Group 2 Trading Program

■ 54. Amend § 97.702 by:

■ a. In the definition of "alternate designated representative", removing "or CSAPR NO_X Ozone Season Group 2 Trading Program, then" and adding in its place "CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, then";

■ b. In the definition of "CSAPR NO_X Ozone Season Group 1 Trading Program", removing "(b)(2)(i) and (ii), and" and adding in its place "(b)(2)(i), and";

■ c. In the definition of "CSAPR NO_X Ozone Season Group 2 Trading Program", removing "(b)(2)(iii) and (iv), and" and adding in its place "(b)(2)(ii), and";

■ d. Adding in alphabetical order a definition for "CSAPR NO_X Ozone Season Group 3 Trading Program"; and

■ e. In the definition of "designated representative", removing "or CSAPR NO_X Ozone Season Group 2 Trading Program, then" and adding in its place "CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, then".

§ 97.702 Definitions.

* * * * *

CSAPR NO_X Ozone Season Group 3 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart GGGGG of this part and § 52.38(b)(1), (b)(2)(iii), and (b)(10) through (14) and (17) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(10) or (11) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(12) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

* * * * *

§ 97.711 [Amended]

■ 55. Amend § 97.711 by:

■ a. In paragraphs (b)(1)(i)(A) and (B), removing "State, in accordance" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance"; and

■ b. In paragraphs (b)(2)(i)(A) and (B), removing "Indian country within the borders of a State, in accordance" and adding in its place "areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance".

§ 97.712 [Amended]

■ 56. Amend § 97.712 by:

■ a. In paragraph (a) introductory text, removing "State, the Administrator" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator";

■ b. In paragraphs (a)(3)(iii) and (a)(5), adding "and areas of Indian country within the borders of the State subject to the State's SIP authority" after "in the State";

■ c. In paragraph (a)(10), removing "State, is allocated" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated";

■ d. In paragraph (b) introductory text, removing "Indian country within the borders of each State, the Administrator" and adding in its place "areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator"; and

■ e. In paragraph (b)(5), removing "Indian country within the borders of the State" and adding in its place "areas of Indian country within the borders of the State not subject to the State's SIP authority".

§ 97.721 [Amended]

■ 57. In § 97.721, amend paragraph (f)(2) by removing ''2022'' and adding in its place ''2024'', and removing ''third'' before ''year after the year''.

§ 97.726 [Amended]

■ 58. In § 97.726, amend paragraph (c) by removing ''State (or Indian'' and adding in its place ''State (and Indian''.

§ 97.734 [Amended]

■ 59. In § 97.734, amend paragraph (d)(3) by removing ''or CSAPR NO_X Ozone Season Group 2 Trading Program, quarterly'' and adding in its place ''CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, quarterly''.

Subpart EEEEE—CSAPR NO_X Ozone Season Group 2 Trading Program

■ 60. Amend § 97.802 by:

■ a. In the definition of ''assurance account'', removing ''base CSAPR'' and adding in its place ''CSAPR'';

■ b. Removing the definitions for ''base CSAPR NO_X Ozone Season Group 2 source'' and ''base CSAPR NO_X Ozone Season Group 2 unit'';

■ c. In the definition of ''common designated representative'', removing ''base CSAPR'' and adding in its place ''CSAPR'';

■ d. In the definition of ''common designated representative's assurance level'', revising paragraph (1);

■ e. In the definition of ''common designated representative's share'', removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears;

■ f. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';

■ g. In the definition of ''CSAPR NO_X Ozone Season Group 3 allowance'', adding ''or (e)'' after ''§ 97.826(d)'', and adding ''or less'' after ''one ton'';

■ h. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and''; and

■ i. In the definition of ''State'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and''.

The revision reads as follows:

§ 97.802 Definitions.

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Common designated representative's assurance level * * *

(1) The amount (rounded to the nearest allowance) equal to the sum of the total amount of CSAPR NO_X Ozone Season Group 2 allowances allocated for such control period to the group of one or more CSAPR NO_X Ozone Season Group 2 units in such State (and such Indian country) having the common designated representative for such control period and the total amount of CSAPR NO_X Ozone Season Group 2 allowances purchased by an owner or operator of such CSAPR NO_X Ozone Season Group 2 units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such CSAPR NO_X Ozone Season Group 2 units in accordance with the CSAPR NO_X Ozone Season Group 2 allowance auction provisions in a SIP revision approved by the Administrator under § 52.38(b)(8) or (9) of this chapter, multiplied by the sum of the State NO_X Ozone Season Group 2 trading budget under § 97.810(a) and the State's variability limit under § 97.810(b) for such control period, and divided by such State NO_X Ozone Season Group 2 trading budget;

* * * * *

§ 97.806 [Amended]

■ 61. In § 97.806, amend paragraphs (c)(2)(i) introductory text, (c)(2)(i)(B), (c)(2)(iii) and (iv), and (c)(3)(ii) by removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears.

§ 97.810 [Amended]

■ 62. In § 97.810, amend paragraphs (a)(1)(i) through (iii), (a)(2)(i) and (ii), (a)(12)(i) through (iii), (a)(13)(i) and (ii), (a)(17)(i) through (iii), (a)(19)(i) and (ii), (a)(20)(i) through (iii), (a)(23)(i) through (iii), and (b)(1), (2), (12), (13), (17), (19), (20), and (23) by removing ''and thereafter'' and adding in its place ''through 2022''.

■ 63. Amend § 97.811 by:

■ a. In paragraphs (b)(1)(i)(A) and (B), removing ''State, in accordance'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance'';

■ b. In paragraphs (b)(2)(i)(A) and (B), removing ''Indian country within the borders of a State, in accordance'' and adding in its place ''areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance'';

■ c. In paragraph (d)(1), removing ''§ 52.38(b)(2)(iv) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(ii)(B) of this chapter (and''; and

■ d. Adding paragraph (e).

The addition reads as follows:

§ 97.811 Timing requirements for CSAPR NO_X Ozone Season Group 2 allowance allocations.

* * * * *

(e) *Recall of CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods after 2022.* (1) Notwithstanding any other provision of this subpart, part 52 of this chapter, or any SIP revision approved under § 52.38(b) of this chapter, the provisions of this paragraph and paragraphs (e)(2) through (7) of this section shall apply with regard to each CSAPR NO_X Ozone Season Group 2 allowance that was allocated for a control period after 2022 to any unit (including a permanently retired unit qualifying for an exemption under § 97.805) in a State listed in § 52.38(b)(2)(ii)(C) of this chapter (and Indian country within the borders of such a State) and that was initially recorded in the compliance account for the source that includes the unit, whether such CSAPR NO_X Ozone Season Group 2 allowance was allocated pursuant to this subpart or pursuant to a SIP revision approved under § 52.38(b) of this chapter and whether such CSAPR NO_X Ozone Season Group 2 allowance remains in such compliance account or has been transferred to another Allowance Management System account.

(2)(i) For each CSAPR NO_X Ozone Season Group 2 allowance described in paragraph (e)(1) of this section that was allocated for a given control period and initially recorded in a given source's compliance account, one CSAPR NO_X Ozone Season Group 2 allowance that was allocated for the same or an earlier control period and initially recorded in the same or any other Allowance Management System account must be surrendered in accordance with the procedures in paragraphs (e)(3) and (4) of this section.

(ii)(A) The surrender requirement under paragraph (e)(2)(i) of this section corresponding to each CSAPR NO_X Ozone Season Group 2 allowance described in paragraph (e)(1) of this section initially recorded in a given source's compliance account shall apply to such source's current owners and operators, except as provided in paragraph (e)(2)(ii)(B) of this section.

(B) If the owners and operators of a given source as of a given date assumed ownership and operational control of the source through a transaction that did not also provide rights to direct the use or transfer of a given CSAPR NO_X Ozone Season Group 2 allowance described in paragraph (e)(1) of this section with regard to such source (whether recordation of such CSAPR NO_X Ozone Season Group 2 allowance in the source's compliance account occurred before such transaction or was anticipated to occur after such transaction), then the surrender requirement under paragraph (e)(2)(i) of this section corresponding to such CSAPR NO_X Ozone Season Group 2 allowance shall apply to the most recent former owners and operators of the source before the occurrence of such a transaction.

(C) The Administrator will not adjudicate any private legal dispute among the owners and operators of a source or among the former owners and operators of a source, including any disputes relating to the requirements to surrender CSAPR NO_X Ozone Season Group 2 allowances for the source under paragraph (e)(2)(i) of this section.

(3)(i) As soon as practicable on or after [EFFECTIVE DATE OF FINAL RULE], the Administrator will send a notification to the designated representative for each source described in paragraph (e)(1) of this section identifying the amounts of CSAPR NO_X Ozone Season Group 2 allowances allocated for each control period after 2022 and recorded in the source's compliance account and the corresponding surrender requirements for the source under paragraph (e)(2)(i) of this section.

(ii) As soon as practicable on or after [15 DAYS AFTER EFFECTIVE DATE OF FINAL RULE], the Administrator will deduct from the compliance account for each source described in paragraph (e)(1) of this section CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy the surrender requirements for the source under paragraph (e)(2)(i) of this section until all such surrender requirements for the source are satisfied or until no more CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy such surrender requirements remain in such compliance account.

(iii) As soon as practicable after completion of the deductions under paragraph (e)(3)(ii) of this section, the Administrator will identify for each source described in paragraph (e)(1) of this section the amounts, if any, of CSAPR NO_X Ozone Season Group 2 allowances allocated for each control period after 2022 and recorded in the source's compliance account for which the corresponding surrender requirements under paragraph (e)(2)(i) of this section have not been satisfied and will send a notification concerning such identified amounts to the designated representative for the source.

(iv) With regard to each source for which unsatisfied surrender requirements under paragraph (e)(2)(i) of this section remain after the deductions under paragraph (e)(3)(ii) of this section:

(A) Except as provided in paragraph (e)(3)(iv)(B) of this section, not later than September 15, 2023, the owners and operators of the source shall hold sufficient CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy such unsatisfied surrender requirements under paragraph (e)(2)(i) of this section in the source's compliance account.

(B) With regard to any portion of such unsatisfied surrender requirements that apply to former owners and operators of the source pursuant to paragraph (e)(2)(ii)(B) of this section, not later than September 15, 2023, such former owners and operators shall hold sufficient CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy such portion of the unsatisfied surrender requirements under paragraph (e)(2)(i) of this section either in the source's compliance account or in another Allowance Management System account identified to the Administrator on or before such date in a submission by the authorized account representative for such account.

(C) As soon as practicable on or after September 15, 2023, the Administrator will deduct from the Allowance Management System account identified in accordance with paragraph (e)(3)(iv)(A) or (B) of this section CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy the surrender requirements for the source under paragraph (e)(2)(i) of this section until all such surrender requirements for the source are satisfied or until no more CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy such surrender requirements remain in such account.

(v) When making deductions under paragraph (e)(3)(ii) or (iv) of this section to address the surrender requirements under paragraph (e)(2)(i) of this section for a given source:

(A) The Administrator will make deductions to address any surrender requirements with regard to first the 2023 control period and then the 2024 control period.

(B) When making deductions to address the surrender requirements with regard to a given control period, the Administrator will first deduct CSAPR NO_X Ozone Season Group 2 allowances allocated for such given control period and will then deduct CSAPR NO_X Ozone Season Group 2 allowances allocated for each successively earlier control period in sequence.

(C) When deducting CSAPR NO_X Ozone Season Group 2 allowances allocated for a given control period from a given Allowance Management System account, the Administrator will first deduct CSAPR NO_X Ozone Season Group 2 allowances initially recorded in the account under § 97.821 (if the account is a compliance account) in the order of recordation and will then deduct CSAPR NO_X Ozone Season Group 2 allowances recorded in the account under § 97.526(d) or § 97.823 in the order of recordation.

(4)(i) To the extent the surrender requirements under paragraph (e)(2)(i) of this section corresponding to any CSAPR NO_X Ozone Season Group 2 allowances allocated for a control period after 2022 and initially recorded in a given source's compliance account have not been fully satisfied through the deductions under paragraph (e)(3) of this section, as soon as practicable on or after November 15, 2023, the Administrator will deduct such initially recorded CSAPR NO_X Ozone Season Group 2 allowances from any Allowance Management System accounts in which such CSAPR NO_X Ozone Season Group 2 allowances are held, making such deductions in any order determined by the Administrator, until all such surrender requirements for such source have been satisfied or until all such CSAPR NO_X Ozone Season Group 2 allowances have been deducted, except as provided in paragraph (e)(4)(ii) of this section.

(ii) If no person with an ownership interest in a given CSAPR NO_X Ozone Season Group 2 allowance as of April 30, 2022, was an owner or operator of the source in whose compliance account such CSAPR NO_X Ozone Season Group 2 allowance was initially recorded, was a direct or indirect parent or subsidiary of an owner or operator of such source, or was directly or indirectly under common ownership with an owner or operator of such source, the Administrator will not deduct such CSAPR NO_X Ozone Season Group 2 allowance under paragraph (e)(4)(i) of this section. For purposes of this paragraph, each owner or operator of a source shall be deemed to be a person with an ownership interest in any CSAPR NO_X Ozone Season Group 2 allowance held in that source's compliance account. The limitation established by this paragraph on the deductibility of certain CSAPR NO_X Ozone Season Group 2 allowances under paragraph (e)(4)(i) of this section shall not be construed as a waiver of the surrender requirements under paragraph (e)(2)(i) of this section corresponding to such CSAPR NO_X Ozone Season Group 2 allowances.

(iii) Not less than 45 days before the planned date for any deductions under paragraph (e)(4)(i) of this section, the Administrator will send a notification to the authorized account representative for the Allowance Management System account from which such deductions will be made identifying the CSAPR NO_X Ozone Season Group 2 allowances to be deducted and the data upon which the Administrator has relied and specifying a process for submission of any objections to such data. Any objections must be submitted to the Administrator not later than 15 days before the planned date for such deductions as indicated in such notification.

(5) To the extent the surrender requirements under paragraph (e)(2)(i) of this section corresponding to any CSAPR NO_X Ozone Season Group 2 allowances allocated for a control period after 2022 and initially recorded in a given source's compliance account have not been fully satisfied through the deductions under paragraphs (e)(3) and (4) of this section:

(i) The persons identified in accordance with paragraph (e)(2)(ii) of this section with regard to such source and each such CSAPR NO_X Ozone Season Group 2 allowance shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(ii) Each such CSAPR NO_X Ozone Season Group 2 allowance, and each day in such control period, shall constitute a separate violation of this subpart and the Clean Air Act.

(6) The Administrator will record in the appropriate Allowance Management System accounts all deductions of CSAPR NO_X Ozone Season Group 2 allowances under paragraphs (e)(3) and (4) of this section.

(7)(i) Each submission, objection, or other written communication from a designated representative, authorized account representative, or other person to the Administrator under paragraph (e)(2), (3), or (4) of this section shall be sent electronically to the email address *CSAPR@epa.gov.* Each such communication from a designated representative must contain the certification statement set forth in § 97.814(a), and each such communication from the authorized account representative for a general account must contain the certification statement set forth in § 97.820(c)(2)(ii).

(ii) Each notification from the Administrator to a designated representative or authorized account representative under paragraph (e)(3) or (4) of this section will be sent electronically to the email address most recently received by the Administrator for such representative. In any such notification, the Administrator may provide information by means of a reference to a publicly accessible website where the information is available.

§ 97.812 [Amended]

■ 64. Amend § 97.812 by:

■ a. In paragraph (a) introductory text, removing ''State, the Administrator'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator'';

■ b. In paragraphs (a)(3)(iii) and (a)(5), adding ''and areas of Indian country within the borders of the State subject to the State's SIP authority'' after ''in the State'';

■ c. In paragraph (a)(10), removing ''State, is allocated'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';

■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator''; and

■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

§ 97.821 [Amended]

■ 65. In § 97.821, amend paragraph (f) by removing ''2022'' and adding in its place ''2024'', and removing ''third'' before ''year after the year''.

§ 97.825 [Amended]

■ 66. In § 97.825, amend paragraphs (a) introductory text, (a)(2), (b)(1)(i), (b)(1)(ii)(A) and (B), (b)(3), (b)(4)(i), (b)(5), (b)(6)(i), (b)(6)(iii) introductory text, and (b)(6)(iii)(A) and (B) by removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears.

■ 67. Amend § 97.826 by:

■ a. In paragraph (b), removing ''(c) or (d)'' and adding in its place ''(c), (d), or (e)'';

■ b. In paragraph (c), removing ''State (or Indian'' and adding in its place ''State (and Indian'';

■ c. In paragraphs (d)(1)(i)(A) and (B), removing ''§ 52.38(b)(2)(iv)'' and adding in its place ''§ 52.38(b)(2)(ii)(B)'';

■ d. Revising paragraph (d)(1)(i)(C);

■ e. In paragraph (d)(1)(ii) introductory text, removing ''§ 52.38(b)(2)(v)'' and adding in its place ''§ 52.38(b)(2)(iii)'';

■ f. Removing and reserving paragraph (d)(1)(iii);

■ g. Revising paragraph (d)(1)(iv) introductory text;

■ h. In paragraphs (d)(1)(iv)(A) and (B), removing ''or (d)(1)(iii)(C)'';

■ i. In paragraphs (d)(2)(i) and (d)(3), removing ''§ 52.38(b)(2)(v) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(iii) of this chapter (and'';

■ j. Redesignating paragraph (e) as paragraph (f) and adding a new paragraph (e);

■ k. Revising newly redesignated paragraphs (f)(1) and (2); and

■ l. Adding paragraph (f)(3).

The revisions and additions read as follows:

§ 97.826 Banking and conversion.

* * * * *

(d) * * *

(1) * * *

(i) * * *

(C) The full-season CSAPR NO_X Ozone Season Group 3 allowance bank target, computed as the sum for all States listed in § 52.38(b)(2)(iii)(A) of this chapter of the variability limits under § 97.1010(e) for such States for the control period in 2022.

* * * * *

(iv) For the compliance account of each source to which an amount of CSAPR NO_X Ozone Season Group 3 allowances greater than zero is allocated under paragraph (d)(1)(ii)(C) of this section:

* * * * *

(e) Notwithstanding any other provision of this subpart, part 52 of this chapter, or any SIP revision approved under § 52.38(b)(8) or (9) of this chapter:

(1) By [45 DAYS AFTER EFFECTIVE DATE OF FINAL RULE], the Administrator will temporarily suspend acceptance of CSAPR NO_X Ozone Season Group 2 allowance transfers submitted under § 97.822 and, before resuming acceptance of such transfers, will take the following actions with regard to every general account and every compliance account except a compliance account for a CSAPR NO_X Ozone Season Group 2 source in a State listed in § 52.38(b)(2)(ii)(A) of this chapter (and Indian country within the borders of such a State):

(i) The Administrator will deduct all CSAPR NO_X Ozone Season Group 2 allowances allocated for the control periods in 2017 through 2022 from each such account.

(ii) The Administrator will determine a conversion factor equal to the greater of 1.0000 or the quotient, expressed to four decimal places, of the sum of all CSAPR NO_X Ozone Season Group 2 allowances deducted from all such accounts under paragraph (e)(1)(i) of this section divided by the sum of the variability limits for the control period in 2024 under § 97.1010(e) for all States listed in § 52.38(b)(2)(iii)(B) of this chapter.

(iii) The Administrator will allocate and record in each such account an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 computed as the quotient, rounded up to the nearest allowance, of the number of CSAPR NO_X Ozone Season Group 2 allowances deducted from such account under paragraph (e)(1)(i) of this section divided by the conversion factor determined under paragraph (e)(1)(ii) of this section, except as provided in paragraph (e)(1)(iv) or (v) of this section.

(iv) Where, pursuant to paragraph (e)(1)(i) of this section, the Administrator deducts CSAPR NO_X Ozone Season Group 2 allowances from the compliance account for a source in a State not listed in § 52.38(b)(2)(iii) of this chapter (and Indian country within the borders of such a State), the Administrator will not record CSAPR NO_X Ozone Season Group 3 allowances in that compliance account but instead will allocate and record the amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 computed for such source in accordance with paragraph (e)(1)(iii) of this section in a general account identified by the designated representative for such source, provided that if the designated representative fails to identify such a general account in a submission to the Administrator by [45 DAYS AFTER EFFECTIVE DATE OF FINAL RULE], the Administrator may record such CSAPR NO_X Ozone Season Group 3 allowances in a general account identified or established by the Administrator with the designated representative as the authorized account representative and with the owners and operators of such source (as indicated on the certificate of representation for the source) as the persons represented by the authorized account representative.

(v)(A) In computing any amounts of CSAPR NO_X Ozone Season Group 3 allowances to be allocated to and recorded in general accounts under paragraph (e)(1)(iii) of this section, the Administrator may group multiple general accounts whose ownership interests are held by the same or related persons or entities and treat the group of accounts as a single account for purposes of such computation.

(B) Following a computation for a group of general accounts in accordance with paragraph (e)(1)(v)(A) of this section, the Administrator will allocate to and record in each individual account in such group a proportional share of the quantity of CSAPR NO_X Ozone Season Group 3 allowances computed for such group, basing such shares on the respective quantities of CSAPR NO_X Ozone Season Group 2 allowances removed from such individual accounts under paragraph (e)(1)(i) of this section.

(C) In determining the proportional shares under paragraph (e)(1)(v)(B) of this section, the Administrator may employ any reasonable adjustment methodology to truncate or round each such share up or down to a whole number and to cause the total of such whole numbers to equal the amount of CSAPR NO_X Ozone Season Group 3 allowances computed for such group of accounts in accordance with paragraph (e)(1)(v)(A) of this section, even where such adjustments cause the numbers of CSAPR NO_X Ozone Season Group 3 allowances allocated to some individual accounts to equal zero.

(2) After the Administrator has carried out the procedures set forth in paragraph (e)(1) of this section, upon any determination that would otherwise result in the initial recordation of a given number of CSAPR NO_X Ozone Season Group 2 allowances in the compliance account for a source in a State listed in § 52.38(b)(2)(iii)(B) of this chapter (and Indian country within the borders of such a State), the Administrator will not record such CSAPR NO_X Ozone Season Group 2 allowances but instead will allocate and record in such account an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 2 allowances divided by the conversion factor determined under paragraph (e)(1)(ii) of this section.

(f) * * *

(1) Except as provided in paragraph (f)(3) of this section, after the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section, the owner or operator of a CSAPR NO_X Ozone Season Group 2 source in a State listed in § 52.38(b)(2)(iii)(A) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Group 2 allowances for the control period in a year from 2017 through 2020 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2021 (or any later control period for which the allowance transfer deadline defined in § 97.1002 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 2 allowances divided by the conversion factor determined under paragraph (d)(1)(i)(D) of this section.

(2) Except as provided in paragraph (f)(3) of this section, after the Administrator has carried out the procedures set forth in paragraph (e)(1) of this section, the owner or operator of a CSAPR NO_X Ozone Season Group 2 source in a State listed in § 52.38(b)(2)(iii)(B) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Group 2 allowances for the control period in a year from 2017 through 2022 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 (or any later control period for which the allowance transfer deadline defined in § 97.1002 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 2 allowances divided by the conversion factor determined under paragraph (e)(1)(ii) of this section.

(3) CSAPR NO_X Ozone Season Group 3 allowances may not be used to satisfy requirements to surrender CSAPR NO_X Ozone Season Group 2 allowances under § 97.811(d) or (e).

Subpart FFFFF—Texas SO_2 Trading Program

■ 68. Amend § 97.902 by:

■ a. In the definition of ''alternate designated representative'', removing ''Program or CSAPR NO_X Ozone Season Group 2 Trading Program, then'' and adding in its place ''Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, then'';

■ b. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';

■ c. Adding in alphabetical order a definition for ''CSAPR NO_X Ozone Season Group 3 Trading Program''; and

■ d. In the definition of ''designated representative'', removing ''Program or CSAPR NO_X Ozone Season Group 2 Trading Program, then'' and adding in its place ''Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, then''.

The addition reads as follows:

§ 97.902 Definitions.

* * * * *

CSAPR NO_X Ozone Season Group 3 Trading Program means a multi-state

NO_X air pollution control and emission reduction program established in accordance with subpart GGGGG of this part and § 52.38(b)(1), (b)(2)(iii), and (b)(10) through (14) and (17) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(10) or (11) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(12) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

* * * * *

§ 97.921 [Amended]

■ 69. In § 97.921, amend paragraph (b)(2) by removing ''2022'' and adding in its place ''2024'', and removing ''third'' before ''year after the year''.

§ 97.934 [Amended]

■ 70. In § 97.934, amend paragraph (d)(3) by removing ''Program or CSAPR NO_X Ozone Season Group 2 Trading Program, quarterly'' and adding in its place ''Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, quarterly''.

Subpart GGGGG—CSAPR NO_X Ozone Season Group 3 Trading Program

■ 71. Amend § 97.1002 by:

■ a. Revising the definition of ''allocate or allocation'';

■ b. In the definition of ''allowance transfer deadline'', adding ''primary'' before ''emissions limitation'';

■ c. In the definition of ''alternate designated representative'', removing ''or CSAPR SO_2 Group 1 Trading Program, then'' and adding in its place ''CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then'';

■ d. Adding in alphabetical order a definition for ''backstop daily NO_X emissions rate'';

■ e. In the definition of ''common designated representative's assurance level'', in paragraph (1), removing ''§ 97.1010(b)'' and adding in its place ''§ 97.1010(e)'', and revising paragraph (2);

■ f. In the definition of ''compliance account'', adding ''primary'' before ''emissions limitation'';

■ g. Adding in alphabetical order a definition for ''CSAPR NO_X Ozone Season Group 1 Trading Program'';

■ h. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';

■ i. In the definition of ''CSAPR NO_X Ozone Season Group 3 allowance'', adding ''or (e)'' after ''§ 97.826(d)'', and adding ''or less'' after ''one ton'';

■ j. In the definition of ''CSAPR NO_X Ozone Season Group 3 allowance deduction or deduct CSAPR NO_X Ozone Season Group 3 allowances'', adding ''primary'' before ''emissions limitation'';

■ k. In the definition of ''CSAPR NO_X Ozone Season Group 3 emissions limitation'', adding ''primary'' before ''emissions limitation'';

■ l. Adding in alphabetical order a definition for ''CSAPR NO_X Ozone Season Group 3 secondary emissions limitation'';

■ m. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and'';

■ n. Adding in alphabetical order a definition for ''CSAPR SO_2 Group 2 Trading Program'';

■ o. In the definition of ''designated representative'', removing ''or CSAPR SO_2 Group 1 Trading Program, then'' and adding in its place ''CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then''.

■ p. In the definition of ''excess emissions'', adding ''primary'' before ''emissions limitation''; and

■ q. In the definition of ''State'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and''.

The revisions and additions read as follows:

§ 97.1002 Definitions.

* * * * *

Allocate or *allocation* means, with regard to CSAPR NO_X Ozone Season Group 3 allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart, §§ 97.526(d) and 97.826(d) and (e), and any SIP revision submitted by the State and approved by the Administrator under § 52.38(b)(10), (11), or (12) of this chapter, of the amount of such CSAPR NO_X Ozone Season Group 3 allowances to be initially credited, at no cost to the recipient, to:

(1) A CSAPR NO_X Ozone Season Group 3 unit;

(2) A new unit set-aside;

(3) An Indian country new unit set-aside;

(4) An Indian country existing unit set-aside; or

(5) An entity not listed in paragraphs (1) through (4) of this definition;

(6) Provided that, if the Administrator, State, or permitting authority initially credits, to a CSAPR NO_X Ozone Season Group 3 unit qualifying for an initial credit, a credit in the amount of zero CSAPR NO_X Ozone Season Group 3 allowances, the CSAPR NO_X Ozone Season Group 3 unit will be treated as being allocated an amount (*i.e.,* zero) of CSAPR NO_X Ozone Season Group 3 allowances.

* * * * *

Backstop daily NO_X emissions rate means an emissions rate limit used in the determination of the CSAPR NO_X Ozone Season Group 3 primary emissions limitation for a CSAPR NO_X Ozone Season Group 3 source in accordance with § 97.1024(b).

* * * * *

Common designated representative's assurance level * * *

(2) Provided that the allocations of CSAPR NO_X Ozone Season Group 3 allowances for any control period taken into account for purposes of this definition shall exclude any CSAPR NO_X Ozone Season Group 3 allowances allocated for such control period under § 97.526(d) or § 97.826(d) or (e).

* * * * *

CSAPR NO_X Ozone Season Group 1 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart BBBBB of this part and § 52.38(b)(1), (b)(2)(i), and (b)(3) through (5) and (13) through (15) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

* * * * *

CSAPR NO_X Ozone Season Group 3 secondary emissions limitation means, for a CSAPR NO_X Ozone Season Group 3 unit to which such a limitation applies under § 97.1025(c)(1) for a control period in a given year, the tonnage of NO_X emissions calculated for the unit in accordance with § 97.1025(c)(2) for such control period.

* * * * *

CSAPR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart DDDDD of this part and § 52.39(a), (c), (g) through (k), and (m) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(g) or (h) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(i) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

* * * * *

■ 72. Amend § 97.1006 by:

■ a. Revising paragraph (b)(2), the paragraph (c)(1) heading, paragraph (c)(1)(i), and paragraph (c)(1)(ii) introductory text;
■ b. Adding paragraphs (c)(1)(iii) and (iv); and
■ c. Revising paragraphs (c)(2)(iii) and (c)(3).

The revisions and additions read as follows:

§ 97.1006 Standard requirements.

* * * * *

(b) * * *

(2) The emissions and heat input data determined in accordance with §§ 97.1030 through 97.1035 shall be used to calculate allocations of CSAPR NO_X Ozone Season Group 3 allowances under §§ 97.1011 and 97.1012 and to determine compliance with the CSAPR NO_X Ozone Season Group 3 primary and secondary emissions limitations 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 §§ 97.1030 through 97.1035 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) * * *

(1) *CSAPR NO_X Ozone Season Group 3 primary and secondary emissions limitations*—(i) *Primary emissions limitation.* As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season Group 3 source and each CSAPR NO_X Ozone Season Group 3 unit at the source shall hold, in the source's compliance account, CSAPR NO_X Ozone Season Group 3 allowances available for deduction for such control period under § 97.1024(a) in an amount not less than the amount determined under § 97.1024(b), comprising the sum of:

(A) The tons of total NO_X emissions for such control period from all CSAPR NO_X Ozone Season Group 3 units at the source; plus

(B) Two times the sum, for all CSAPR NO_X Ozone Season Group 3 units at the source and all days of the control period, of any NO_X emissions from such a unit on any day of the control period exceeding the NO_X emissions that would have occurred on that day if the unit had combusted the same daily heat input and emitted at any backstop daily NO_X emissions rate applicable to the unit for that control period.

(ii) *Exceedances of primary emissions limitation.* If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season Group 3 units at a CSAPR NO_X Ozone Season Group 3 source are in excess of the CSAPR NO_X Ozone Season Group 3 primary emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

* * * * *

(iii) *Secondary emissions limitation.* The owner or operator of a base CSAPR NO_X Ozone Season Group 3 unit subject to an emissions limitation under § 97.1025(c)(1) shall not discharge, or allow to be discharged, emissions of NO_X to the atmosphere during a control period in excess of the tonnage amount calculated in accordance with § 97.1025(c)(2).

(iv) *Exceedances of secondary emissions limitation.* If total NO_X emissions during a control period in a given year from a base CSAPR NO_X Ozone Season Group 3 unit are in excess of the amount of a CSAPR NO_X Ozone Season Group 3 secondary emissions limitation applicable to the unit for the control period under paragraph (c)(1)(iii) of this section, then the owners and operators of the unit and the source at which the unit is located shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and 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) * * *

(iii) Total NO_X emissions from all base CSAPR NO_X Ozone Season Group 3 units at base CSAPR NO_X Ozone Season Group 3 sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season Group 3 trading budget under § 97.1010(a) and the State's variability limit under § 97.1010(e).

* * * * *

(3) *Compliance periods.*(i) A CSAPR NO_X Ozone Season Group 3 unit shall be subject to the requirements under paragraphs (c)(1)(i) and (ii) of this section, and a base CSAPR NO_X Ozone Season Group 3 unit shall be subject to the requirements under paragraph (c)(2) of this section, for the control period starting on the later of the applicable date in paragraph (c)(3)(i)(A), (B), or (C) of this section or the deadline for meeting the unit's monitor certification requirements under § 97.1030(b) and for each control period thereafter:

(A) May 1, 2021, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(A) of this chapter;

(B) May 1, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(B) of this chapter; or

(C) [EFFECTIVE DATE OF FINAL RULE], for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(C) of this chapter.

(ii) A base CSAPR NO_X Ozone Season Group 3 unit shall be subject to the requirements under paragraphs (c)(1)(iii) and (iv) of this section for the control period starting on the later of May 1, 2024 or the deadline for meeting the unit's monitor certification requirements under § 97.1030(b) and for each control period thereafter.

* * * * *

■ 73. Revise § 97.1010 to read as follows:

§ 97.1010 State NO_X Ozone Season Group 3 trading budgets, set-asides, and variability limits.

(a) *State NO_X Ozone Season Group 3 trading budgets.* (1)(i) The State NO_X Ozone Season Group 3 trading budgets for allocations of CSAPR NO_X Ozone Season Group 3 allowances for the control periods in 2021, 2022, 2023, and 2024 are as indicated in Table 1 to this paragraph, subject to prorating for the control period in 2023 as provided in paragraph (a)(1)(ii) of this section:

TABLE 1 TO PARAGRAPH (a)(1)(i)—STATE NO_X OZONE SEASON GROUP 3 TRADING BUDGETS BY CONTROL PERIOD

[Tons]

State	2021	2022	Portion of 2023 control period before [EFFECTIVE DATE OF FINAL RULE], before prorating	Portion of 2023 control period on and after [EFFECTIVE DATE OF FINAL RULE], before prorating	2024
Alabama			13,211	6,364	6,306
Arkansas			9,210	8,889	8,889
Delaware				384	434
Illinois	11,223	9,102	8,179	7,364	7,463
Indiana	17,004	12,582	12,553	11,151	9,391
Kentucky	17,542	14,051	14,051	11,640	11,640
Louisiana	16,291	14,818	14,818	9,312	9,312
Maryland	2,397	1,266	1,266	1,187	1,187
Michigan	14,384	12,290	9,975	10,718	10,718
Minnesota				3,921	3,921
Mississippi			6,315	5,024	4,400
Missouri			15,780	11,857	11,857
Nevada				2,280	2,372
New Jersey	1,565	1,253	1,253	799	799
New York	4,079	3,416	3,421	3,763	3,763
Ohio	13,481	9,773	9,773	8,369	8,369
Oklahoma			11,641	10,265	9,573
Pennsylvania	12,071	8,373	8,373	8,855	8,855
Tennessee			7,736	4,234	4,234
Texas			52,301	38,284	38,284
Utah				14,981	15,146
Virginia	6,331	3,897	3,980	3,090	2,814
West Virginia	15,062	12,884	12,884	12,478	12,478
Wisconsin			7,915	5,963	5,057
Wyoming				9,125	8,573

(ii) For the control period in 2023, the State NO_X Ozone Season Group 3 trading budget for each State shall be calculated as the sum of the following prorated amounts, rounded to the nearest allowance:

(A) The product of the non-prorated trading budget for the portion of the 2023 control period before [EFFECTIVE DATE OF FINAL RULE] shown for the State in Table 1 to paragraph (a)(1)(i) of this section (or zero if Table 1 shows no amount for such portion of the 2023 control period for the State) multiplied by a fraction whose numerator is the number of days from May 1, 2023 through the day before [EFFECTIVE DATE OF FINAL RULE], inclusive, and whose denominator is 153; and

(B) The product of the non-prorated trading budget for the portion of the 2023 control period on and after [EFFECTIVE DATE OF FINAL RULE] shown for the State in Table 1 to paragraph (a)(1)(i) of this section multiplied by a fraction whose numerator is the number of days from [EFFECTIVE DATE OF FINAL RULE] through September 30, 2023, inclusive, and whose denominator is 153.

(2) The State NO_X Ozone Season Group 3 trading budget for each State and each control period in 2025 and thereafter shall be the amount provided for the State and control period in the applicable notice of data availability issued under paragraph (a)(3)(v)(C) of this section.

(3) The Administrator will calculate the State NO_X Ozone Season Group 3 trading budget for each State and each control period in 2025 and thereafter in the year before the year of the control period as follows:

(i) The State's trading budget for the control period shall be calculated as the sum (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton), for all units identified for inclusion in the calculation under paragraph (a)(3)(ii) of this section, of the product for each such unit of the NO_X emissions rate in lb/mmBtu identified for the unit under paragraph (a)(3)(iii) of this section multiplied by the heat input in mmBtu identified for the unit under paragraph (a)(3)(iv) of this section.

(ii) A unit in a State (and Indian country within the borders of the State) shall be included in the calculation of the State's trading budget for a control period if:

(A) The unit was included in the calculation of the State's trading budget for the immediately preceding control period; or

(B) The unit's deadline for certification of monitoring systems under § 97.1030(b) is on or before May 1 of the year two years before the year of the control period (*e.g.,* May 1, 2023 for calculation of the trading budget for the control period in 2025);

(C) Provided that a unit shall not be included in the calculation of a State's trading budget for a control period if, before completing such calculation, the Administrator determines that the unit is not actually a CSAPR NO_X Ozone Season Group 3 unit.

(iii) For each unit included in the calculation of the State's trading budget for a control period, the NO_X emissions rate in lb/mmBtu used in the calculation shall be identified as follows:

(A) For a unit listed in the table entitled ''Dynamic Budget 2023 Template'' and ''Dynamic Budget 2026+ Template'' posted at *www.regulations.gov* with docket identification number EPA–HQ–OAR–2021–0668–[XXXX], the NO_X emissions rate used in the calculation for the control period shall be the NO_X emissions rate shown for the unit and control period in the tables.

(B) For a unit not listed in the table referenced in paragraph (a)(3)(iii)(A) of this section, the NO_X emissions rate used in the calculation for the control period shall be identified according to the type of unit and the type of fuel combusted by the unit during the control period beginning May 1 on or immediately after the unit's deadline for certification of monitoring systems under § 97.1030(b) as follows:

(*1*) 0.012 lb/mmBtu, for a combined cycle combustion turbine other than an integrated coal gasification combined cycle unit;

(*2*) 0.030 lb/mmBtu, for a simple cycle combustion turbine or a boiler combusting only fuel oil or gaseous fuel (other than coal-derived fuel) during such control period; or

(*3*) 0.050 lb/mmBtu, for a boiler combusting any amount of coal or coal-derived fuel during such control period or any other unit not covered by paragraph (a)(3)(iii)(B)(*1*) or (*2*) of this section.

(iv) For each unit included in the calculation of the State's trading budget for a control period, the heat input in mmBtu used in the calculation shall be identified as follows:

(A) Except as provided in paragraph (a)(3)(iv)(B) of this section, the heat input used in the calculation for the control period shall be the heat input reported for the unit for the control period in the year two years before the year of the control period (*e.g.,* heat input reported for the control period in 2023 shall be used in calculating the trading budget for the control period in 2025).

(B) If no heat input data were reported for the unit for the control period in the year two years before the year of the control period and the heat input used for the unit in calculating the State's trading budget for the control period in 2024 was an estimate rather than the unit's actual reported heat input for the control period in 2021 or an earlier year, the same estimated heat input used in calculating the State's trading budget for the control period in 2024 shall be used in the calculations of the State's trading budgets for the control periods in 2025 and 2026.

(v)(A) By March 1, 2024 and March 1 of each year thereafter, the Administrator will calculate the State CSAPR NO_X Ozone Season Group 3 trading budget for each State, in accordance with paragraph (a)(3)(i) through (iv) of this section and §§ 97.1006(b)(2) and 97.1030 through 97.1035, for the control period in the year after the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(B) For each notice of data availability required in paragraph (a)(3)(v)(A) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice. Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations (including the identification of the units included in the calculations) are in accordance with the provisions referenced in paragraph (a)(3)(v)(A) of this section.

(C) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (a)(3)(v)(A) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (a)(3)(v)(A) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (a)(3)(v)(B) of this section.

(b) *New unit set-asides.* (1) The States' new unit set-asides for allocations of CSAPR NO_X Ozone Season Group 3 allowances for the control periods in 2021, 2022, 2023, and 2024 are as indicated in Table 2 to this paragraph:

TABLE 2 TO PARAGRAPH (b)(1)—NEW UNIT SET-ASIDES BY CONTROL PERIOD

[Tons]

State	2021	2022	2023	2024
Alabama			191	189
Arkansas			178	178
Delaware			54	61
Illinois	265	265	368	373
Indiana	262	254	223	188
Kentucky	309	283	233	233
Louisiana	430	430	186	186
Maryland	135	115	24	24
Michigan	500	482	429	429
Minnesota			78	78
Mississippi			100	88
Missouri			237	237
Nevada			137	142
New Jersey	27	27	16	16
New York	168	168	188	188
Ohio	291	290	418	418
Oklahoma			205	191
Pennsylvania	335	339	266	266
Tennessee			85	85
Texas			766	766
Utah			449	454
Virginia	185	161	155	141
West Virginia	266	261	250	250
Wisconsin			119	101
Wyoming			274	257

(2) The new unit set-aside for allocations of CSAPR NO_X Ozone Season Group 3 allowances for each State for each control period in 2025 and thereafter shall be calculated as the product (rounded to the nearest allowance) of the State NO_X Ozone Season Group 3 trading budget determined for the State and control period under paragraph (a)(2) of this section multiplied by 0.02.

(c) *Indian country new unit set-asides for the control periods in 2021 and 2022.* The States' Indian country new unit set-asides for allocations of CSAPR NO_X Ozone Season Group 3 allowances for the control periods in 2021 and 2022 are as indicated in Table 3 to this paragraph:

TABLE 3 TO PARAGRAPH (c)—INDIAN COUNTRY NEW UNIT SET-ASIDES BY CONTROL PERIOD

[Tons]

State	2021	2022
Alabama		
Arkansas		
Delaware		
Illinois		
Indiana		
Kentucky		
Louisiana	15	15
Maryland		
Michigan	13	12
Minnesota		
Mississippi		
Missouri		
Nevada		
New Jersey		
New York	3	3
Ohio		
Oklahoma		
Pennsylvania		
Tennessee		
Texas		
Utah		
Virginia		
West Virginia		
Wisconsin		
Wyoming		

(d) *Indian country existing unit set-asides for the control periods in 2023 and thereafter.* The Indian country existing unit set-aside for allocations of CSAPR NO_X Ozone Season Group 3 allowances for each State for each control period in 2023 and thereafter shall be calculated as the sum of all allowance allocations to units in areas of Indian country within the borders of the State not subject to the State's SIP authority as provided in the applicable notice of data availability for the control period referenced in § 97.1011(a)(2).

(e) *Variability limits.* (1) The variability limit for the State NO_X Ozone Season Group 3 trading budget for each State for each control period from 2021 through 2024 shall be calculated as the product (rounded to the nearest ton) of the State NO_X Ozone Season Group 3 trading budget determined for the State and control period in accordance with paragraph (a)(1) of this section multiplied by 0.21.

(2) The variability limit for the State NO_X Ozone Season Group 3 trading budget for each State for each control period in 2025 and thereafter shall be calculated as the product (rounded to the nearest ton) of the State NO_X Ozone Season Group 3 trading budget determined for the State and control period in accordance with paragraph (a)(2) of this section multiplied by the greater of:

(i) 0.21; or

(ii) Any excess over 1.00 of the quotient (rounded to two decimal places) of the total heat input reported for the control period for all CSAPR NO_X Ozone Season Group 3 units in the State and Indian country within the borders of the State divided by the total heat input used in the calculation of the State's trading budget for the control period under paragraph (a)(3) of this section.

(f) *Relationship of trading budgets, set-asides, and variability limits.* Each State NO_X Ozone Season Group 3 trading budget in this section includes any tons in a new unit set-aside, Indian country new unit set-aside, or Indian country existing unit set-aside but does not include any tons in a variability limit.

■ 74. Amend § 97.1011 by revising the section heading and paragraphs (a), (b), and (c)(1) and (5) to read as follows:

§ 97.1011 CSAPR NO_X Ozone Season Group 3 allowance allocations to existing units.

(a) *Allocations to existing units in general.* (1) For the control periods in 2021 and each year thereafter, CSAPR NO_X Ozone Season Group 3 allowances will be allocated to units in each State and areas of Indian country within the borders of the State subject to the State's SIP authority as provided in notices of data availability issued by the Administrator. Starting with the control period in 2025, the notices of data availability will be the notices issued under paragraph (b)(10)(iii) of this section.

(2) For the control periods in 2023 and each year thereafter, CSAPR NO_X Ozone Season Group 3 allowances will be allocated to units in areas of Indian country within the borders of each State not subject to the State's SIP authority as provided in notices of data availability issued by the Administrator. Starting with the control period in 2025, the notices of data availability will be the notices issued under paragraph (b)(10)(iii) of this section.

(3) Providing an allocation to a unit in a notice of data availability does not constitute a determination that the unit is a CSAPR NO_X Ozone Season Group 3 unit, and not providing an allocation to a unit in such notice does not constitute a determination that the unit is not a CSAPR NO_X Ozone Season Group 3 unit.

(b) *Calculation of default allocations to existing units for control periods in 2025 and thereafter.* For each control period in 2025 and thereafter, and for the CSAPR NO_X Ozone Season Group 3 units in each State and areas of Indian country within the borders of the State, the Administrator will calculate default allocations of CSAPR NO_X Ozone Season Group 3 allowances to the CSAPR NO_X Ozone Season Group 3 units as follows:

(1) For each State and control period, the total amount of CSAPR NO_X Ozone Season Group 3 allowances for which default allocations will be calculated will be the remainder of the State NO_X Ozone Season Group 3 trading budget for the control period under § 97.1010(a)(2) minus the new unit set-aside for the control period under § 97.1010(b)(2).

(2) A default allocation of CSAPR NO_X Ozone Season Group 3 allowances will be calculated for a CSAPR NO_X Ozone Season Group 3 unit in the State and Indian country within the borders of the State for a control period if:

(i) The unit meets the conditions under § 97.1010(a)(3)(ii) to be included in the calculation of the State's trading budget for the control period; and

(ii) The unit reported heat input greater than zero for the control period in the year two years before the year of the control period.

(3) For each CSAPR NO_X Ozone Season Group 3 unit for which a default allocation is being calculated for a control period, the Administrator will determine the following amounts for the five-year historical period ending with the year two years before the year of the control period for which default allocations are being calculated:

(i) The total heat input reported for the unit in accordance with part 75 of this chapter for the control period in each year of the five-year historical period;

(ii) The average of the three highest of the total heat input values determined for the unit under paragraph (b)(3)(i) of this section or, if fewer than three non-zero values were determined for the unit, the average of all such non-zero heat input values;

(iii) The total NO_X emissions reported for the unit in accordance with part 75 of this chapter for the control period in each year of the five-year historical period; and

(iv) The maximum of the total NO_X emissions values determined for the unit under paragraph (b)(3)(iii) of this section.

(4) The Administrator will calculate the initial unrounded default allocations for each CSAPR NO_X Ozone Season Group 3 unit according to the procedure in paragraph (b)(5) of this section and will recalculate the unrounded default allocations according to the procedures in paragraph (b)(6) or (7) of this section, as applicable, iterating the recalculations as necessary until the total of the unrounded default allocations to all eligible units equals the amount of allowances determined for the State under paragraph (b)(1) of this section.

(5) The Administrator will calculate the initial unrounded default allocations to CSAPR NO_X Ozone Season Group 3 units as follows:

(i) The Administrator will calculate the sum, for all units determined under paragraph (b)(2) of this section to be eligible to receive a default allocation, of the units' average heat input determined under paragraph (b)(3)(ii) of this section.

(ii) For each unit determined under paragraph (b)(2) of this section to be eligible to receive a default allocation, the Administrator will calculate the unit's unrounded default allocation as the lesser of:

(A) The product of the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section multiplied by a fraction whose numerator is the unit's average heat input determined under paragraph (b)(3)(ii) of this section and whose denominator is the sum determined under paragraph (b)(5)(i) of this section; and

(B) The unit's maximum total NO_X emissions determined under paragraph (b)(3)(iv) of this section.

(iii) If the sum of the unrounded default allocations determined under paragraph (b)(5)(ii) of this section is less than the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will follow the procedures in paragraph (b)(6) or (7) of this section, as applicable.

(iv) If the sum of the unrounded default allocations determined under paragraph (b)(5)(ii) of this section equals the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will determine the rounded default allocations according to the procedures in paragraphs (b)(8) and (9) of this section.

(6) If the unrounded default allocation determined in the previous round of the calculation procedure for at least one CSAPR NO_X Ozone Season Group 3 unit is less than the unit's maximum total NO_X emissions determined under paragraph (b)(3)(iv) of this section, the Administrator will recalculate the unrounded default allocations as follows:

(i) The Administrator will calculate the additional pool of allowances to be allocated as the remainder of the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section minus the sum of the unrounded default allocations from the previous round of the calculation procedure for all units determined under paragraph (b)(2) of this section to be eligible to receive a default allocation.

(ii) The Administrator will calculate the sum, for all units whose unrounded default allocations determined in the previous round of the calculation procedure were less than the respective units' maximum total NO_X emissions determined under paragraph (b)(3)(iv) of this section, of the units' average heat input determined under paragraph (b)(3)(ii) of this section.

(iii) For each unit whose unrounded default allocation determined in the previous round of the calculation was less than the unit's maximum total NO_X emissions determined under paragraph (b)(3)(iv) of this section, the Administrator will recalculate the unit's unrounded default allocation, before rounding, as the lesser of:

(A) The sum of the unit's unrounded default allocation determined in the previous round of the calculation procedure plus the product of the additional pool of allowances determined under paragraph (b)(6)(i) of this section multiplied by a fraction whose numerator is the unit's average heat input determined under paragraph (b)(3)(ii) of this section and whose denominator is the sum determined under paragraph (b)(6)(ii) of this section; and

(B) The unit's maximum total NO_X emissions determined under paragraph (b)(3)(iv) of this section.

(iv) Except as provided in paragraph (b)(6)(iii) of this section, a unit's unrounded default allocation shall equal the amount determined in the previous round of the calculation procedure.

(v) If the sum of the unrounded default allocations determined under paragraphs (b)(6)(iii) and (iv) of this section is less than the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will iterate the procedures in paragraph (b)(6) of this section or follow the procedures in paragraph (b)(7) of this section, as applicable.

(vi) If the sum of the unrounded default allocations determined under paragraphs (b)(6)(iii) and (iv) of this section equals the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will determine the rounded default allocations according to the procedures in paragraphs (b)(8) and (9) of this section.

(7) If the unrounded default allocation determined in the previous round of the calculation procedure for every CSAPR NO_X Ozone Season Group 3 unit equals the unit's maximum total NO_X emissions determined under paragraph (b)(3)(iv) of this section, the Administrator will recalculate the unrounded default allocations as follows:

(i) The Administrator will calculate the additional pool of allowances to be allocated as the remainder of the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section minus the sum of the unrounded default allocations from the previous round for all units determined under paragraph (b)(2) of this section to be eligible to receive a default allocation.

(ii) The Administrator will recalculate the unrounded default allocation for each eligible unit as the sum of:

(A) The unit's unrounded default allocation as determined in the previous round of the calculation procedure; plus

(B) The product of the additional pool of allowances determined under paragraph (b)(7)(i) of this section multiplied by a fraction whose numerator is the unit's average heat input determined under paragraph (b)(3)(ii) of this section and whose denominator is the sum determined under paragraph (b)(5)(i) of this section.

(8) The Administrator will round the default allocation for each eligible unit determined under paragraph (b)(5), (6), or (7) of this section to the nearest allowance and make any adjustments required under paragraph (b)(9) of this section.

(9) If the sum of the default allocations after rounding under paragraph (b)(8) of this section does not equal the total amount of allowances determined for the State and control period under paragraph (b)(1) of this

section, the Administrator will adjust the default allocations as follows. The Administrator will list the CSAPR NO_X Ozone Season Group 3 units in descending order based on such units' allocation amounts under paragraph (b)(8) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant sources' names and numerical order of the relevant units' identification numbers, and will adjust each unit's allocation amount upward or downward by one CSAPR NO_X Ozone Season Group 3 allowance (but not below zero) in the order in which the units are listed, and will repeat this adjustment process as necessary, until the total of the adjusted default allocations equals the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section.

(10)(i) By March 1, 2024 and March 1 of each year thereafter, the Administrator will calculate the default allocation of CSAPR NO_X Ozone Season Group 3 allowances to each CSAPR NO_X Ozone Season Group 3 unit in a State and Indian country within the borders of the State, in accordance with paragraphs (b)(1) through (9) of this section and §§ 97.1006(b)(2) and 97.1030 through 97.1035, for the control period in the year after the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(10)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice. Objections shall be submitted by the deadline specified in such notice of data availability and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_X Ozone Season Group 3 units) are in accordance with the provisions referenced in paragraph (b)(10)(i) of this section.

(iii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(10)(i) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(10)(i) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(10)(ii) of this section.

(c) *Incorrect allocations of CSAPR NO_X Ozone Season Group 3 allowances to existing units.* (1) For each control period in 2021 and thereafter, if the Administrator determines that CSAPR NO_X Ozone Season Group 3 allowances were allocated for the control period to a recipient covered by the provisions of paragraph (c)(1)(i), (ii), or (iii) of this section, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section:

(i) The recipient is not actually a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004 as of the first day of the control period and is allocated CSAPR NO_X Ozone Season Group 3 allowances for such control period under paragraph (a)(1) or (2) of this section;

(ii) The recipient is not actually a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004 as of the first day of the control period and is allocated CSAPR NO_X Ozone Season Group 3 allowances for such control period under a provision of a SIP revision approved under § 52.38(b)(10), (11), or (12) of this chapter that the SIP revision provides should be allocated only to recipients that are CSAPR NO_X Ozone Season Group 3 units as of the first day of such control period; or

(iii) The recipient is not located as of the first day of the control period in the State (and Indian country within the borders of the State) from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances allocated under paragraph (a)(1) or (2) of this section, or under a provision of a SIP revision approved under § 52.38(b)(10), (11), or (12) of this chapter, were allocated for such control period.

* * * * *

(5) With regard to any CSAPR NO_X Ozone Season Group 3 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section:

(i) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs on or before May 1, 2024, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside for 2021, 2022, or 2023 for the State from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances were allocated.

(ii) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs after May 1, 2024 and on or before May 1 of the year following the year of the control period for which the CSAPR NO_X Ozone Season Group 3 allowances were allocated, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside for such control period for the State from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances were allocated.

(iii) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs after May 1, 2024 and after May 1 of the year following the year of the control period for which the CSAPR NO_X Ozone Season Group 3 allowances were allocated, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to a surrender account.

■ 75. Amend § 97.1012 by:

■ a. Revising paragraphs (a) introductory text and (a)(1)(i) and (ii);

■ b. Removing paragraphs (a)(1)(iii) and (iv);

■ c. Revising paragraphs (a)(2) and (a)(3)(i);

■ d. In paragraph (a)(3)(ii), adding ''and'' after the semicolon;

■ e. Revising paragraph (a)(3)(iii);

■ f. Removing paragraph (a)(3)(iv);

■ g. Revising paragraphs (a)(5) and (10):

■ h. In paragraph (a)(11), removing ''§ 97.1011(b)(1)(i), (ii), and (v), of'' and adding in its place ''paragraph (a)(13) of this section, of'';

■ i. Adding paragraph (a)(13);

■ j. Revising paragraphs (b) introductory text and (b)(1) and (2);

■ k. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';

■ l. Revising paragraph (b)(10);

■ m. In paragraph (b)(11), removing ''§ 97.1011(b)(2)(i), (ii), and (v), of'' and adding in its place ''paragraph (b)(13) of this section, of''; and

■ n. Adding paragraphs (b)(13) and (c).

The revisions and additions read as follows:

§ 97.1012 CSAPR NO_X Ozone Season Group 3 allowance allocations to new units.

(a) *Allocations from new unit set-asides.* For each control period in 2021 and thereafter for a State listed in § 52.38(b)(2)(iii)(A) of this chapter, or 2023 and thereafter for a State listed in § 52.38(b)(2)(iii)(B) or (C) of this chapter, and for the CSAPR NO_X Ozone Season Group 3 units in each State and areas of

Indian country within the borders of the State (except, for the control periods in 2021 and 2022, areas of Indian country within the borders of the State not subject to the State's SIP authority), the Administrator will allocate CSAPR NO_X Ozone Season Group 3 allowances to the CSAPR NO_X Ozone Season Group 3 units as follows:

(1) * * *

(i) CSAPR NO_X Ozone Season Group 3 units that are not allocated an amount of CSAPR NO_X Ozone Season Group 3 allowances for such control period in the applicable notice of data availability referenced in § 97.1011(a)(1) or (2) and that have deadlines for certification of monitoring systems under § 97.1030(b) not later than September 30 of the year of the control period; or

(ii) CSAPR NO_X Ozone Season Group 3 units whose allocation of an amount of CSAPR NO_X Ozone Season Group 3 allowances for such control period in the applicable notice of data availability referenced in § 97.1011(a)(1) or (2) is covered by § 97.1011(c)(2) or (3).

(2) The Administrator will establish a separate new unit set-aside for the State for each such control period. Each such new unit set-aside will be allocated CSAPR NO_X Ozone Season Group 3 allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.1010(b) and will be allocated additional CSAPR NO_X Ozone Season Group 3 allowances (if any) in accordance with § 97.1011(c)(5) and paragraphs (b)(10) and (c)(5) of this section.

(3) * * *

(i) The control period in 2021, for a State listed in § 52.38(b)(2)(iii)(A) of this chapter, or the control period in 2023, for a State listed in § 52.38(b)(2)(iii)(B) or (C) of this chapter;

* * * * *

(iii) For a unit described in paragraph (a)(1)(ii) of this section, the first control period in which the CSAPR NO_X Ozone Season Group 3 unit operates in the State and Indian country within the borders of the State (except, for the control periods in 2021 and 2022, areas of Indian country within the borders of the State not subject to the State's SIP authority) after operating in another jurisdiction and for which the unit is not already allocated one or more CSAPR NO_X Ozone Season Group 3 allowances.

* * * * *

(5) The Administrator will calculate the sum of the allocation amounts of CSAPR NO_X Ozone Season Group 3 allowances determined for all such CSAPR NO_X Ozone Season Group 3 units under paragraph (a)(4)(i) of this section in the State and Indian country within the borders of the State (except, for the control periods in 2021 and 2022, areas of Indian country within the borders of the State not subject to the State's SIP authority) for such control period.

* * * * *

(10)(i) For a control period in 2021 or 2022, if, after completion of the procedures under paragraphs (a)(2) through (7) and (12) of this section for a control period, any unallocated CSAPR NO_X Ozone Season Group 3 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each CSAPR NO_X Ozone Season Group 3 unit that is in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and is allocated an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in the applicable notice of data availability referenced in § 97.1011(a)(1) an amount of CSAPR NO_X Ozone Season Group 3 allowances equal to the following: The total amount of such remaining unallocated CSAPR NO_X Ozone Season Group 3 allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.1011(a)(1) for such control period, divided by the remainder of the amount of tons in the applicable State NO_X Ozone Season Group 3 trading budget minus the sum of the amounts of tons in such new unit set-aside and the Indian country new unit set-aside for the State for such control period, and rounded to the nearest allowance.

(ii) For a control period in 2023 or thereafter, if, after completion of the procedures under paragraphs (a)(2) through (7) and (12) of this section for a control period, any unallocated CSAPR NO_X Ozone Season Group 3 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each CSAPR NO_X Ozone Season Group 3 unit that is in the State and Indian country within the borders of the State and is allocated an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period by the Administrator in the applicable notice of data availability referenced in § 97.1011(a)(1) or (2), or under a provision of a SIP revision approved under § 52.38(b)(10), (11), or (12) of this chapter, an amount of CSAPR NO_X Ozone Season Group 3 allowances equal to the following: The total amount of such remaining unallocated CSAPR NO_X Ozone Season Group 3 allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.1011(a)(1) or (2) or a provision of a SIP revision approved under § 52.38(b)(10), (11), or (12) of this chapter for such control period, divided by the remainder of the amount of tons in the applicable State NO_X Ozone Season Group 3 trading budget minus the amount of tons in such new unit set-aside for the State for such control period, and rounded to the nearest allowance.

* * * * *

(13)(i) By March 1, 2022 and March 1 of each year thereafter, the Administrator will calculate the CSAPR NO_X Ozone Season Group 3 allowance allocation to each CSAPR NO_X Ozone Season Group 3 unit in a State and Indian country within the borders of the State (except, for the control periods in 2021 and 2022, areas of Indian country within the State not subject to the State's SIP authority), in accordance with paragraphs (a)(2) through (7), (10), and (12) of this section and §§ 97.1006(b)(2) and 97.1030 through 97.1035, for the control period in the year before the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (a)(13)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice. Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_X Ozone Season Group 3 units) are in accordance with the provisions referenced in paragraph (a)(13)(i) of this section.

(iii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (a)(13)(i) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (a)(13)(i) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (a)(13)(ii) of this section.

(b) *Allocations from Indian country new unit set-asides.* For the control periods in 2021 and 2022, for a State listed in § 52.38(b)(2)(iii)(A) of this chapter, and for the CSAPR NO_X Ozone

Season Group 3 units in areas of Indian country within the borders of each such State not subject to the State's SIP authority, the Administrator will allocate CSAPR NO_X Ozone Season Group 3 allowances to the CSAPR NO_X Ozone Season Group 3 units as follows:

(1) The CSAPR NO_X Ozone Season Group 3 allowances will be allocated to CSAPR NO_X Ozone Season Group 3 units that are not allocated an amount of CSAPR NO_X Ozone Season Group 3 allowances for such control period in the applicable notice of data availability issued under § 97.1011(a)(1) and that have deadlines for certification of monitoring systems under § 97.1030(b) not later than September 30 of the year of the control period, except as provided in paragraph (b)(10) of this section.

(2) The Administrator will establish a separate Indian country new unit set-aside for the State for each such control period. Each such Indian country new unit set-aside will be allocated CSAPR NO_X Ozone Season Group 3 allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.1010(c) and will be allocated additional CSAPR NO_X Ozone Season Group 3 allowances (if any) in accordance with paragraph (c)(5) of this section.

* * * * *

(10) If, after completion of the procedures under paragraphs (b)(2) through (7) and (12) of this section for a control period, any unallocated CSAPR NO_X Ozone Season Group 3 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will transfer such unallocated CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside for the State for such control period.

* * * * *

(13)(i) By March 1, 2022 and March 1, 2023, the Administrator will calculate the CSAPR NO_X Ozone Season Group 3 allowance allocation to each CSAPR NO_X Ozone Season Group 3 unit in areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance with paragraphs (b)(2) through (7), (10), and (12) of this section and §§ 97.1006(b)(2) and 97.1030 through 97.1035, for the control period in the year before the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(13)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice. Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_X Ozone Season Group 3 units) are in accordance with the provisions referenced in paragraph (b)(13)(i) of this section.

(iii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(13)(i) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(13)(i) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(13)(ii) of this section.

(c) *Incorrect allocations of CSAPR NO_X Ozone Season Group 3 allowances to new units.* (1) For each control period in 2021 and thereafter, if the Administrator determines that CSAPR NO_X Ozone Season Group 3 allowances were allocated for the control period under paragraphs (a)(2) through (7) and (12) of this section or paragraphs (b)(2) through (7) and (12) of this section to a recipient that is not actually a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004 as of the first day of such control period, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such CSAPR NO_X Ozone Season Group 3 allowances under § 97.1021.

(3) If the Administrator already recorded such CSAPR NO_X Ozone Season Group 3 allowances under § 97.1021 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the source that includes such recipient under § 97.1024(b) for such control period, then the Administrator will deduct from the account in which such CSAPR NO_X Ozone Season Group 3 allowances were recorded an amount of CSAPR NO_X Ozone Season Group 3 allowances allocated for the same or a prior control period equal to the amount of such already recorded CSAPR NO_X Ozone Season Group 3 allowances. The authorized account representative shall ensure that there are sufficient CSAPR NO_X Ozone Season Group 3 allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such CSAPR NO_X Ozone Season Group 3 allowances under § 97.1021 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the source that includes such recipient under § 97.1024(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded CSAPR NO_X Ozone Season Group 3 allowances.

(5) With regard to any CSAPR NO_X Ozone Season Group 3 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section:

(i) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs on or before May 1, 2023, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside, in the case of allowances allocated under paragraph (a) of this section, or the Indian country new unit set-aside, in the case of allowances allocated under paragraph (b) of this section, for the control period in 2021 or 2022 for the State from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances were allocated.

(ii) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs after May 1, 2023 and on or before May 1, 2024, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside for the control period in 2023 for the State from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances were allocated.

(iii) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs after May 1, 2024, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to a surrender account.

■ 76. Amend § 97.1021 by:

■ a. In paragraph (a), removing "§ 97.1011(a)" and adding in its place "§ 97.1011(a)(1)";

■ b. Revising paragraph (b);

■ c. Removing and reserving paragraph (c);

■ d. Revising paragraph (d);

■ e. Adding paragraph (e);

■ f. Revising paragraphs (f) and (g);

■ g. In paragraph (h), removing ''May 1 of each year thereafter, the'' and adding in its place ''May 1, 2023, the'';

■ h. Adding paragraphs (i) and (j); and

■ i. In paragraph (m), adding ''or (e)'' after ''§ 97.811(d)'' each time it appears.

The revisions and addition read as follows:

§ 97.1021 Recordation of CSAPR NO_X Ozone Season Group 3 allowance allocations and auction results.

* * * * *

(b) By July 29, 2021, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2022.

* * * * *

(d) By [30 DAYS AFTER EFFECTIVE DATE OF FINAL RULE], the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2023.

(e) By [30 DAYS AFTER EFFECTIVE DATE OF FINAL RULE], the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2024, unless the State in which the source is located notifies the Administrator in writing by [EFFECTIVE DATE OF FINAL RULE] of the State's intent to submit to the Administrator a complete SIP revision by September 1, 2023 meeting the requirements of § 52.38(b)(10)(i) through (iv) of this chapter.

(1) If, by September 1, 2023 the State does not submit to the Administrator such complete SIP revision, the Administrator will record by September 15, 2023 in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2024.

(2) If the State submits to the Administrator by September 1, 2023 and the Administrator approves by March 1, 2024 such complete SIP revision, the Administrator will record by March 1, 2024 in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source as provided in such approved, complete SIP revision for the control period in 2024.

(3) If the State submits to the Administrator by September 1, 2023 and the Administrator does not approve by March 1, 2024 such complete SIP revision, the Administrator will record by March 1, 2024 in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2024.

(f) By July 1, 2024 and July 1 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_X Ozone Season Group 3 allowances auctioned to CSAPR NO_X Ozone Season Group 3 units, in accordance with § 97.1011(a)(1), or with a SIP revision approved under § 52.38(b)(11) or (12) of this chapter, for the control period in the year after the year of the applicable recordation deadline under this paragraph.

(g) By May 1, 2022 and May 1 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1012(a) for the control period in the year before the year of the applicable recordation deadline under this paragraph.

* * * * *

(i) By [30 DAYS AFTER EFFECTIVE DATE OF FINAL RULE], the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(2) for the control periods in 2023 and 2024.

(j) By July 1, 2024 and July 1 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(2) for the control period in the year after the year of the applicable recordation deadline under this paragraph.

* * * * *

■ 77. Amend § 97.1024 by:

■ a. Revising the section heading;

■ b. In paragraphs (a) introductory text and (b) introductory text, adding ''primary'' before ''emissions limitation'';

■ c. Revising paragraph (b)(1);

■ d. Adding paragraph (b)(3); and

■ e. In paragraph (c)(2)(ii), adding ''or (e)'' after ''§ 97.826(d)''.

The revisions and addition read as follows:

§ 97.1024 Compliance with CSAPR NO_X Ozone Season Group 3 primary emissions limitation.

* * * * *

(b) * * *

(1) Until the amount of CSAPR NO_X Ozone Season Group 3 allowances deducted equals the sum of:

(i) The number of tons of total NO_X emissions from all CSAPR NO_X Ozone Season Group 3 units at the source for such control period; plus

(ii) Two times the sum (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton), for all days in the control period and all CSAPR NO_X Ozone Season Group 3 units at the source to which backstop daily NO_X emissions rates apply for the control period under paragraph (b)(3) of this section, of any amount by which a unit's NO_X emissions for a given day in pounds exceed the product in pounds of the unit's total heat input in mmBtu for that day multiplied by the applicable backstop daily NO_X emissions rate in lb/mmBtu; or

* * * * *

(3) The applicable backstop daily NO_X emissions rates are as follows:

(i) For the control periods in 2024 and each year thereafter, a backstop daily NO_X emissions rate of 0.14 lb/mmBtu shall apply to each CSAPR NO_X Ozone Season Group 3 unit combusting any coal during the control period, serving a generator with nameplate capacity of 100 MW or more, and equipped with selective catalytic reduction controls, except a circulating fluidized bed boiler.

(ii) For the control periods in 2027 and each year thereafter, a backstop daily NO_X emissions rate of 0.14 lb/mmBtu shall apply to each CSAPR NO_X Ozone Season Group 3 unit combusting any coal during the control period and serving a generator with nameplate capacity of 100 MW or more, except a circulating fluidized bed boiler.

* * * * *

■ 78. Amend § 97.1025 by revising the section heading and adding paragraph (c) to read as follows:

§ 97.1025 Compliance with CSAPR NO_X Ozone Season Group 3 assurance provisions; CSAPR NO_X Ozone Season Group 3 secondary emissions limitation.

* * * * *

(c) *CSAPR NO_X Ozone Season Group 3 secondary emissions limitation.* (1) The owner or operator of a base CSAPR NO_X Ozone Season Group 3 unit shall not discharge, or allow to be discharged, emissions of NO_X to the atmosphere during a control period in excess of the tonnage amount calculated in accordance with paragraph (c)(2) of this section, provided that the emissions limitation established under this paragraph shall apply to a unit for a control period only if:

(i) The unit is included for the control period in a group of base CSAPR NO_X Ozone Season Group 3 units at base CSAPR NO_X Ozone Season Group 3 sources in a State (and Indian country within the borders of such State) having a common designated representative and the owners and operators of such units and sources are subject to a requirement for such control period to hold one or more CSAPR NO_X Ozone Season Group 3 allowances under § 97.1006(c)(2)(i) and paragraph (b) of this section with respect to such group; and

(ii) The unit was required to report NO_X emissions and heat input data for all or portions of at least 367 operating hours during the control period and all or portions of at least 367 operating hours during at least one previous control period under the CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program.

(2) The amount of the emissions limitation applicable to a base CSAPR NO_X Ozone Season Group 3 unit for a control period under paragraph (c)(1) of this section, in tons of NO_X, shall be calculated as the sum of 50 plus the product (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton) of multiplying—

(i) The total heat input in mmBtu reported for the unit for the control period in accordance with §§ 97.1030 through 97.1035; and

(ii) A NO_X emission rate of 0.10 lb/mmBtu or, if higher, the product of 1.25 times the lowest seasonal average NO_X emission rate in lb/mmBtu achieved by the unit in any previous control period for which the unit was required to report NO_X emissions and heat input data for all or portions of at least 367 operating hours under the CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, where the unit's seasonal average NO_X emission rate for each such previous control period shall be calculated from such reported data as the quotient of the unit's total NO_X emissions in tons for the control period divided by the unit's total heat input in mmBtu for the control period, multiplied by a conversion factor of 2,000 lb/ton, and rounded to the nearest 0.0001 lb/mmBtu.

■ 79. Amend § 97.1026 by:

■ a. Revising paragraph (b);

■ b. In paragraph (c), removing ''State (or Indian'' and adding in its place ''State (and Indian''; and

■ c. Adding paragraph (d).

The revision and addition read as follows:

§ 97.1026 Banking.

* * * * *

(b) Any CSAPR NO_X Ozone Season Group 3 allowance that is held in a compliance account or a general account will remain in such account unless and until the CSAPR NO_X Ozone Season Group 3 allowance is deducted or transferred under § 97.1011(c), § 97.1012(c), § 97.1023, § 97.1024, § 97.1025, § 97.1027, or § 97.1028 or paragraph (c) or (d) of this section.

* * * * *

(d) Before the allowance transfer deadline for each control period in 2024 or a subsequent year, the Administrator will deduct amounts of CSAPR NO_X Ozone Season Group 3 allowances issued for the control periods in previous years exceeding the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target for the control period in accordance with paragraphs (d)(1) through (4) of this section.

(1) As soon as practicable on or after August 1, 2024 and August 1 of each subsequent year, the Administrator will temporarily suspend acceptance of CSAPR NO_X Ozone Season Group 3 allowance transfers submitted under § 97.1022 and, before resuming acceptance of such transfers, will take the actions in paragraphs (d)(2) through (4) of this section.

(2) The Administrator will determine each of the following values:

(i) The CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target for the control period in the year of the deadline under paragraph (d)(1) of this section, calculated as the product, rounded to the nearest allowance, of 0.105 times the sum for all States listed in § 52.38(b)(2)(iii) of this chapter of the State NO_X Ozone Season Group 3 trading budgets under § 97.1010(a) for such States for such control period.

(ii) The total amount of CSAPR NO_X Ozone Season Group 3 allowances issued for control periods in years before the year of the deadline under paragraph (d)(1) of this section and held in all compliance and general accounts.

(3) If the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target determined under paragraph (d)(2)(i) of this section is less than the total amount of CSAPR NO_X Ozone Season Group 3 allowances determined under paragraph (d)(2)(ii) of this section, then for each compliance account or general account holding CSAPR NO_X Ozone Season Group 3 allowances issued for control periods in years before the year of the deadline under paragraph (d)(1) of this section, the Administrator will:

(i) Determine the total amount of CSAPR NO_X Ozone Season Group 3 allowances issued for control periods in years before the year of the deadline under paragraph (d)(1) of this section and held in the account.

(ii) Determine the account's share of the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target for the control period, calculated as the product, rounded up to the nearest allowance, of the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target determined under paragraph (d)(2)(i) of this section multiplied by a fraction whose numerator is the total amount of CSAPR NO_X Ozone Season Group 3 allowances held in the account determined under paragraph (d)(3)(i) of this section and whose denominator is the total amount of CSAPR NO_X Ozone Season Group 3 allowances held in all compliance and general accounts determined under paragraph (d)(2)(ii) of this section.

(iii) Deduct an amount of CSAPR NO_X Ozone Season Group 3 allowances issued for control periods in years before the year of the deadline under paragraph (d)(1) of this section equal to any positive remainder of the total amount of CSAPR NO_X Ozone Season Group 3 allowances held in the account determined under paragraph (d)(3)(i) of this section minus the account's share of the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target for the control period determined under paragraph (d)(3)(ii) of this section. The allowances will be deducted on a first-in, first-out basis in the order set forth in § 97.1024(c)(2)(i) and (ii).

(iv) Record the deductions under paragraph (d)(3)(iii) of this section in the account.

(4)(i) In computing any amounts of CSAPR NO_X Ozone Season Group 3 allowances to be deducted from general accounts under paragraph (d)(3) of this section, the Administrator may group multiple general accounts whose ownership interests are held by the same or related persons or entities and treat the group of accounts as a single account for purposes of such computation.

(ii) Following a computation for a group of general accounts in accordance with paragraph (d)(4)(i) of this section, the Administrator will deduct from and record in each individual account in such group a proportional share of the quantity of CSAPR NO_X Ozone Season Group 3 allowances computed for such group, basing such shares on the respective quantities of CSAPR NO_X Ozone Season Group 3 allowances determined for such individual accounts under paragraph (d)(3)(i) of this section.

(iii) In determining the proportional shares under paragraph (d)(4)(ii) of this section, the Administrator may employ any reasonable adjustment methodology to truncate or round each such share up or down to a whole number and to cause the total of such whole numbers to equal the amount of CSAPR NO_X Ozone Season Group 3 allowances computed for such group of accounts in accordance with paragraph (d)(4)(i) of this section, even where such adjustments cause the numbers of CSAPR NO_X Ozone Season Group 3 allowances remaining in some individual accounts following the deductions to equal zero.

■ 80. Amend § 97.1030 by:

■ a. Revising paragraph (b)(1); and

■ b. In paragraph (b)(3), removing ''(b)(2)'' and adding in its place ''(b)(1) or (2)''.

The revision reads as follows:

§ 97.1030 General monitoring, recordkeeping, and reporting requirements.

* * * * *

(b) * * *

(1)(i) May 1, 2021, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(A) of this chapter;

(ii) May 1, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(B) of this chapter;

(iii) [EFFECTIVE DATE OF FINAL RULE], for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(C) of this chapter, where the unit is required to report NO_X mass emissions data or NO_X emissions rate data according to 40 CFR part 75 to address other regulatory requirements; or

(iv) [180 DAYS AFTER EFFECTIVE DATE OF FINAL RULE] for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(C) of this chapter, where the unit is not required to report NO_X mass emissions data or NO_X emissions rate data according to 40 CFR part 75 to address other regulatory requirements.

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■ 81. Amend § 97.1034 by:

■ a. Revising paragraph (d)(2)(i); and

■ b. In paragraph (d)(4), removing ''or CSAPR SO_2 Group 1 Trading Program, quarterly'' and adding in its place ''CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, quarterly''.

The revision reads as follows:

§ 97.1034 Recordkeeping and reporting.

* * * * *

(d) * * *

(2) * * *

(i)(A) The calendar quarter covering May 1, 2021 through June 30, 2021, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(A) of this chapter;

(B) The calendar quarter covering May 1, 2023 through June 30, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(B) of this chapter; or

(C) The calendar quarter covering [EFFECTIVE DATE OF FINAL RULE] through June 30, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(C) of this chapter;

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